

**Draft
Air Individual Permit
Major Amendment
16300110-102**

Permittee: Northern Natural Gas Co - Hugo

Facility name: Northern Natural Gas Co - Hugo
10825 180th St
Forest Lake, MN 55025
Washington County

Operating permit issuance date: May 22, 1997

Expiration date: Non-expiring

* All Title I Conditions do not expire

Major Amendment: [TBD]

Permit characteristics: State; Nonmajor for Part 70/ True minor for NSR; True Minor for NSR

The emission units, control equipment and emission stacks at the stationary source authorized in this permit amendment are as described in the submittals listed in the Permit Applications Table.

This permit amendment supersedes Air Emission Permit No. 16300110-101 and authorizes the Permittee to construct and operate the stationary source at the address listed above unless otherwise noted in the permit. The Permittee must comply with all the conditions of the permit. Any changes or modifications to the stationary source must be performed in compliance with Minn. R. 7007.1150 to 7007.1500. Terms used in the permit are as defined in the state air pollution control rules unless the term is explicitly defined in the permit.

Unless otherwise indicated, all the Minnesota rules cited as the origin of the permit terms are incorporated into the SIP under 40 CFR § 52.1220 and as such are enforceable by U.S. Environmental Protection Agency (EPA) Administrator or citizens under the Clean Air Act.

Signature: ()

This document has been electronically signed.

for Steven S. Pak, P.E., Manager
Air Quality Permits Section
Industrial Division

for the Minnesota Pollution Control Agency

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Permit issued: [month day, year]
Permit expires: [month day, year]

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1. Permit applications table

Title description	Application receipt date	Action number
Major Amendment	03/05/2026 (supplemental information received on 5/27/2026 and 6/16/2026)	16300110-102
Minor Amendment	03/13/2015	16300110-101
Administrative Amendment	12/19/2001	16300110-002
State Permit	02/28/1997	16300110-001

2. Where to send submittals

Send submittals that are required to be submitted to the EPA regional office to:

Chief Air Enforcement
Air and Radiation Branch
EPA Region V
77 West Jackson Boulevard
Chicago, Illinois 60604

Each submittal must be postmarked or received by the date specified in the applicable Table. Those submittals required by Minn. R. 7007.0100 to 7007.1850 must be certified by a responsible official, defined in Minn. R. 7007.0100, subp. 21. Other submittals shall be certified as appropriate if certification is required by an applicable rule or permit condition.

Send submittals that are required by the Acid Rain Program to:

U.S. Environmental Protection Agency
Clean Air Markets Division
1200 Pennsylvania Avenue NW (6204M)
Washington, D.C. 20460

Send any application for a permit or permit amendment to:

Fiscal Services – 6th Floor
Minnesota Pollution Control Agency
520 Lafayette Road North
St. Paul, Minnesota 55155-4194

Also, where required by an applicable rule or permit condition, send to the Permit Document Coordinator notices of:

- a. Accumulated insignificant activities
- b. Installation of control equipment
- c. Replacement of an emissions unit, and
- d. Changes that contravene a permit term

Unless another person is identified in the applicable Table, send all other submittals to:

AQ Compliance Tracking Coordinator
Industrial Division
Minnesota Pollution Control Agency
520 Lafayette Road North
St. Paul, Minnesota 55155-4194

Or

Email a signed and scanned PDF copy to:
submitstacktest.pca@state.mn.us
(for submittals related to stack testing)
AQRoutineReport.PCA@state.mn.us
(for other compliance submittals)
(See complete email instructions in “Routine Air Report Instructions Letter” at
<https://www.pca.state.mn.us/sites/default/files/aq-f6-15.pdf>)

3. Facility description

The Northern Natural Gas Co - Hugo (Facility) is located at 10825 180th Street, Forest Lake, Washington County, Minnesota.

The facility uses a natural gas-fired turbine to compress natural gas in a pipeline. The facility operates an emergency generator as backup power. The primary emissions from natural gas combustion are nitrogen oxides and carbon monoxide.

This permit action authorizes the construction of one natural gas-fired combustion turbine and emergency generator. These units will replace the existing turbine and emergency generator. The existing turbine, emergency generator, and the new units will not operate simultaneously due to physical capacity limits at the facility. This permit restricts the turbine's operating hours at low-temperature, low load, and startup and shutdown events.

4. Summary of subject items

SI ID: Description	Relationship type	Related SI ID: Description
TFAC 1: Northern Natural Gas Co - Hugo		
ACTV 1: All IAs		
EQUI 1: Gas Turbine Compressor	sends to	STRU 1: Turbine Stack
EQUI 3: Back up Generator	sends to	STRU 3: Generator Stack
EQUI 4: Natural Gas- Fired Turbine	sends to	STRU 1: Turbine Stack
EQUI 5: Emergency Generator	sends to	STRU 4: Emergency

SI ID: Description	Relationship type	Related SI ID: Description
		Generator Stack
FUGI 1: Fugitive emissions components		
FUGI 4: Compressor Blowdown		
STRU 1: Turbine Stack		
STRU 3: Generator Stack		
STRU 4: Emergency Generator Stack		

5. Limits and other requirements

Requirement number	Requirement and citation
TFAC 1	Northern Natural Gas Co - Hugo
5.1.1	Permit Appendices: This permit contains appendices as listed in the permit Table of Contents. The Permittee shall comply with all requirements contained in Appendices: Appendix A: Insignificant Activities and Applicable Requirements; Appendix B: 40 CFR pt. 60, subp. A - General Provisions; Appendix C: 40 CFR pt. 60, subp. JJJJ - Standards of Performance for Stationary Spark Ignition Internal Combustion Engines; Appendix D: 40 CFR pt. 60, subp. KKKKa - Standards of Performance for Stationary Combustion Turbines; Appendix E: 40 CFR pt. 60, subp. OOOOb - Standards of performance for crude oil and natural gas facilities for which construction, modification or reconstruction commenced after December 6, 2022; and Appendix H: 40 CFR pt.60 subp. GG - Standards of performance for Stationary Gus Turbine. [Minn. R. 7007.0800, subp. 2(A) & (B)]
5.1.2	The Permittee must comply with Minn. Stat. 116.385. The Permittee may not use trichloroethylene at its permitted facility including in any manufacturing, processing, or cleaning processes, except as described in Minn. Stat. 116.385, subd. 2(b) and 4. This is a state-only requirement and is not enforceable by the U.S. Environmental Protection Agency (EPA) Administrator and citizens under the Clean Air Act. [Minn. R. 7007.0100, subp. 7(X), Minn. Stat. 116.385]
5.1.3	PERMIT SHIELD: Subject to the limitations in Minn. R. 7007.1800, compliance with the conditions of this permit shall be deemed compliance with the specific provision of the applicable requirement identified in the permit as the basis of each condition. Subject to the limitations of Minn. R. 7007.1800 and 7017.0100, subp. 2, notwithstanding the conditions of this permit specifying compliance practices for applicable requirements, any person (including the Permittee) may also use other credible evidence to establish compliance or noncompliance with applicable requirements. This permit shall not alter or affect the liability of the Permittee for any violation of applicable requirements prior to or at the time of permit issuance. [Minn. R. 7007.1800(A)(2)]
5.1.4	The Permittee must comply with National Primary and Secondary Ambient Air Quality Standards, 40 CFR pt. 50, and the Minnesota Ambient Air Quality Standards, Minn. R. 7009.0010 to 7009.0090. Compliance must be demonstrated upon written request by the MPCA. [Minn. R. 7007.0800, subp. 2(A) & (B), Minn. R. 7009.0020-7009.0090, Minn. Stat. 116.07, subd. 4a(a)]
5.1.5	Circumvention: Do not install or use a device or means that conceals or dilutes emissions, which would otherwise violate a federal or state air pollution control rule, without reducing the total amount of pollutant emitted. [Minn. R. 7011.0020]
5.1.6	The Permittee must at all times properly operate and maintain the facilities and systems of treatment and control and the appurtenances related to them that are installed or used by the Permittee to achieve compliance with the conditions of the permit. Proper operation and maintenance includes effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. [Minn. R. 7007.0800, subp. 16(J)]
5.1.7	Operation and Maintenance Plan: Retain at the stationary source an operation and maintenance plan for all air pollution control equipment. At a minimum, the O & M plan shall identify all air pollution control equipment and control practices and shall include a preventative maintenance program for the equipment and practices, a description of (the minimum but not necessarily the only) corrective

Requirement number	Requirement and citation
	actions to be taken to restore the equipment and practices to proper operation to meet applicable permit conditions, a description of the employee training program for proper operation and maintenance of the control equipment and practices, and the records kept to demonstrate plan implementation. [Minn. R. 7007.0800, subp. 14, Minn. R. 7007.0800, subp. 16(J)]
5.1.8	Operation Changes: In any shutdown, breakdown, or deviation the Permittee must immediately or as soon as possible considering plant and personnel safety take all practical steps to modify operations to reduce the emission of any regulated air pollutant. No emissions units that have an unreasonable shutdown or breakdown frequency of process or control equipment are permitted to operate. [Minn. R. 7019.1000, subp. 4]
5.1.9	Fugitive Emissions: Do not cause or permit the handling, use, transporting, or storage of any material in a manner which may allow avoidable amounts of particulate matter to become airborne. Comply with all other requirements listed in Minn. R. 7011.0150. [Minn. R. 7011.0150]
5.1.10	Noise: The Permittee shall comply with the noise standards set forth in Minn. R. 7030.0010 to 7030.0080 at all times during the operation of any emission units. This is a state only requirement and is not enforceable by the U.S. Environmental Protection Agency (EPA) Administrator and citizens under the Clean Air Act. [Minn. R. 7030.0010-7030.0080]
5.1.11	Inspections: The Permittee shall comply with the inspection procedures and requirements as found in Minn. R. 7007.0800, subp. 9(A). [Minn. R. 7007.0800, subp. 9(A)]
5.1.12	The Permittee shall comply with the General Conditions listed in Minn. R. 7007.0800, subp. 16. [Minn. R. 7007.0800, subp. 16]
5.1.13	Performance Testing: Conduct all performance tests in accordance with Minn. R. ch. 7017 unless otherwise noted in this permit. [Minn. R. ch. 7017]
5.1.14	Performance Test Notifications and Submittals: Performance Test Notification and Plan: due 30 days before each Performance Test Performance Test Pre-test Meeting: due seven days before each Performance Test Performance Test Report: due 45 days after each Performance Test The Notification, Test Plan, and Test Report must be submitted in a format specified by the commissioner. [Minn. R. 7017.2017, Minn. R. 7017.2030, subps. 1-4, Minn. R. 7017.2035, subps. 1-2]
5.1.15	Limits set as a result of a performance test (conducted before or after permit issuance) apply until superseded as stated in the MPCA's Notice of Compliance letter granting preliminary approval. Preliminary approval is based on formal review of a subsequent performance test on the same unit as specified by Minn. R. 7017.2025, subp. 3. The limit is final upon issuance of a permit amendment incorporating the change. [Minn. R. 7017.2025, subp. 3]
5.1.16	Monitoring Equipment Calibration - The Permittee shall either: 1. Calibrate or replace required monitoring equipment every 12 months; or 2. Calibrate at the frequency stated in the manufacturer's specifications. For each monitor, the Permittee shall maintain a record of all calibrations, including the date conducted, and any corrective action that resulted. The Permittee shall include the calibration frequencies, procedures, and manufacturer's specifications (if applicable) in the Operations and Maintenance Plan. Any requirements applying to continuous emission monitors are listed separately in this permit. [Minn. R. 7007.0800, subp. 4(D)]
5.1.17	Operation of Monitoring Equipment: Unless noted elsewhere in this permit, monitoring a process or control equipment connected to that process is not necessary during periods when the process is shutdown, or during checks of the monitoring systems, such as calibration checks and zero and span adjustments. If monitoring records are required, they should reflect any such periods of process

Requirement number	Requirement and citation
	shutdown or checks of the monitoring system. [Minn. R. 7007.0800, subp. 4(D)]
5.1.18	Recordkeeping: Retain all records at the stationary source, unless otherwise specified within this permit, for five (5) years from the date of monitoring, sample, measurement, or report. Records which must be retained at this location include all calibration and maintenance records, all original recordings for continuous monitoring instrumentation, and copies of all reports required by the permit. Records must conform to the requirements listed in Minn. R. 7007.0800, subp. 5(A). [Minn. R. 7007.0800, subp. 5(C)]
5.1.19	Recordkeeping: Maintain records describing any insignificant modifications (as required by Minn. R. 7007.1250, subp. 3) or changes contravening permit terms (as required by Minn. R. 7007.1350, subp. 2), including records of the emissions resulting from those changes. [Minn. R. 7007.0800, subp. 5(B)]
5.1.20	If the Permittee determines that no permit amendment or notification is required prior to making a change, the Permittee must retain records of all calculations required under Minn. R. 7007.1200. For non-expiring permits, these records shall be kept for a period of five years from the date that the change was made. The records shall be kept at the stationary source for the current calendar year of operation and may be kept at the stationary source or office of the stationary source for all other years. The records may be maintained in either electronic or paper format. [Minn. R. 7007.1200, subp. 4]
5.1.21	Shutdown Notifications: Notify the commissioner at least 24 hours in advance of a planned shutdown of any control equipment or process equipment if the shutdown would cause any increase in the emissions of any regulated air pollutant. If the Permittee does not have advance knowledge of the shutdown, the Permittee must notify the commissioner as soon as possible after the shutdown. However, notification is not required in the circumstances outlined in items A, B, and C of Minn. R. 7019.1000, subp. 3. At the time of notification, the owner or operator must inform the commissioner of the cause of the shutdown and the estimated duration. The owner or operator must notify the commissioner when the shutdown is over. [Minn. R. 7019.1000, subp. 3]
5.1.22	Breakdown Notifications: Notify the commissioner within 24 hours of a breakdown of more than one hour of any control equipment or process equipment if the breakdown causes any increase in the emissions of any regulated air pollutant. The 24-hour time period starts when the breakdown was discovered or reasonably should have been discovered by the owner or operator. However, notification is not required in the circumstances outlined in items A, B, and C of Minn. R. 7019.1000, subp. 2. At the time of notification or as soon as possible thereafter, the Permittee must inform the commissioner of the cause of the breakdown and the estimated duration. The Permittee must notify the commissioner when the breakdown is over. [Minn. R. 7019.1000, subp. 2]
5.1.23	Notification of Deviations Endangering Human Health or the Environment: Immediately after discovery of the deviation or immediately after when the deviation reasonably should have been discovered, notify the commissioner either orally or by e-mail, or telephone the state duty officer at 800-422-0798 or 651-649-5451, of any deviation from permit conditions that could endanger human health or the environment. [Minn. R. 7019.1000, subp. 1]
5.1.24	Notification of Deviations Endangering Human Health or the Environment Report: Within two working days of discovery, notify the commissioner in writing of any deviation from permit conditions that could endanger human health or the environment. Include the following information in this written description: 1. the cause of the deviation; 2. the exact dates of the period of the deviation, if the deviation has been corrected; 3. whether or not the deviation has been corrected; 4. the anticipated time by which the deviation is expected to be corrected, if not yet corrected; and

Requirement number	Requirement and citation
	5. steps taken or planned to reduce, eliminate, and prevent reoccurrence of the deviation. [Minn. R. 7019.1000, subp. 1]
5.1.25	Application for Permit Amendment: If a permit amendment is needed, submit an application in accordance with the requirements of Minn. R. 7007.1150 through Minn. R. 7007.1500. Submittal dates vary, depending on the type of amendment needed. Upon adoption of a new or amended federal applicable requirement, and if there are three or more years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150 - 7007.1500]
5.1.26	Extension Requests: The Permittee may apply for an Administrative Amendment to extend a deadline in a permit by no more than 120 days, provided the proposed deadline extension meets the requirements of Minn. R. 7007.1400, subp. 1(H). Performance testing deadlines from the General Provisions of 40 CFR pt. 60 and pt. 63 are examples of deadlines for which the MPCA does not have authority to grant extensions and therefore do not meet the requirements of Minn. R. 7007.1400, subp. 1(H). [Minn. R. 7007.1400, subp. 1(H)]
5.1.27	Within 15 days of a request from the Commissioner, the Permittee must provide a complete summary of all performance tests required at the facility including the subject item, pollutant, most recent test date (if applicable), and the date of the next test in an approved format. [Minn. R. 7007.0800, subp. 16(L)]
5.1.28	Emission Inventory Report: due on or before April 1 of each calendar year following permit issuance. Submit in a format specified by the Commissioner. [Minn. R. 7019.3000-7019.3100]
5.1.29	Emission Fees: due 30 days after receipt of an MPCA bill. [Minn. R. 7002.0005-7002.0085]
EQUI 1	Gas Turbine Compressor
5.2.1	The Permittee shall remove and/or dismantle before initial startup of EQUI 4. [Minn. R. 7007.0800, subp. 2(A)]
5.2.2	Opacity <= 20 percent opacity once operating temperatures have been attained. [Minn. R. 7011.2300, subp. 1]
5.2.3	Sulfur Dioxide <= 0.0015 pounds per million Btu heat input. The potential to emit from the unit is 0.0014 lb/MMBtu due to equipment design and allowable fuels. [Minn. R. 7011.2300, subp. 2(B)]
5.2.4	The Permittee shall keep records of fuel type and usage on a monthly basis. [Minn. R. 7007.0800, subp. 5]
5.2.5	Sulfur Content of Fuel <= 0.8 percent by weight. [40 CFR 60.333, Minn. R. 7011.2350]
5.2.6	Nitrogen Oxides <= 0.00157 percent by volume 25 percent oxygen and on a dry basis when combusting natural gas. [40 CFR 60.332(d), Minn. R. 7011.2350]
5.2.7	Fuel Type: Limited to pipeline natural gas meeting the definition in 40 CFR 60.331(u). [Minn. R. 7005.0100, subp. 35a, Minn. R. 7007.0800, subp. 2(A)]
5.2.8	Turbine Component Replacement Recordkeeping: The Permittee must record the date and nature of each component replacement no later than five business days after completion of each replacement. The Permittee must also record the total cost of the component replacement compared to the cost of an entirely new stationary gas turbine (as defined at 40 CFR 60.4420a). This record must be made at least 30 days before a NOx test is conducted on the gas turbine (as a result of the component replacement), but no later than 180 days after each component replacement. [Minn. R. 7007.0800, subp. 2(A), Minn. R. 7007.0800, subp. 4, Minn. R. 7007.0800, subp. 5]
5.2.9	The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. GG as follows:

Requirement number	Requirement and citation
	40 CFR 60.330(a)-(b); 40 CFR 60.330(d); 40 CFR 60.331; 40 CFR 60.332(a)(2); 40 CFR 60.332(a)(4); 40 CFR 60.332(c); 40 CFR 60.333(b); 40 CFR 60.334(h); 40 CFR 60.334(i)(2); 40 CFR 60.334(j)(1)(ii); 40 CFR 60.334(j)(2)(i); 40 CFR 60.334(j)(2)(iii); and 40 CFR 60.334(j)(5). A copy of 40 CFR pt. 60, subp. GG is included in Appendix H. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than three years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR pt. 60, subp. GG, Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.2350]
5.2.10	The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. A as follows: 40 CFR 60.1(a)-(c); 40 CFR 60.2; 40 CFR 60.3; 40 CFR 60.4; 40 CFR 60.5(a); 40 CFR 60.5(b); 40 CFR 60.6(a); 40 CFR 60.6(b); 40 CFR 60.7(a)(1); 40 CFR 60.7(a)(3); 40 CFR 60.7(a)(4); 40 CFR 60.7(a)(5); 40 CFR 60.7(a)(6); 40 CFR 60.7(a)(7); 40 CFR 60.7(b)-(d); 40 CFR 60.9; 40 CFR 60.11(a)-(d); 40 CFR 60.11(e)(1)-(8); 40 CFR 60.11(f); 40 CFR 60.11(g); 40 CFR 60.12; 40 CFR 60.13(a)-(c); 40 CFR 60.13(d)(1); 40 CFR 60.13(d)(2); 40 CFR 60.13(e)(1); 40 CFR 60.13(e)(2); 40 CFR 60.13(f); 40 CFR 60.13(g);

Requirement number	Requirement and citation
	40 CFR 60.13(h)(1)-(3); 40 CFR 60.13(i)(1)-(9); 40 CFR 60.13(j)(1)-(2); 40 CFR 60.14(a)-(l); 40 CFR 60.15(a)-(g); 40 CFR 60.17; 40 CFR 60.18(b)-(f); 40 CFR 60.18(g)-(i); 40 CFR 60.19(a)-(e); and 40 CFR 60.19(f)(1)-(4). A copy of 40 CFR pt. 60, subp. A is included in Appendix B. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than three years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR pt. 60, subp. A, 40 CFR pt. 60, subp. GG, Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.0050, subp. 1(A), Minn. R. 7011.2350, Minn. R. 7017.1010 & 7017.2015, subp. 2, Minn. R. 7019.0100]
EQUI 3	Back up Generator
5.3.1	The Permittee shall remove and/or dismantle before initial startup of EQUI 5. [Minn. R. 7007.0800, subp. 2(A)]
5.3.2	Opacity <= 20 percent opacity once operating temperatures have been attained. [Minn. R. 7011.2300, subp. 1]
5.3.3	Sulfur Dioxide <= 0.0015 pounds per million Btu heat input. The potential to emit from the unit is 0.000588 lb/MMBtu due to equipment design and allowable fuels. [Minn. R. 7011.2300, subp. 2(B)]
5.3.4	Fuel type: Natural gas only, by design. [Minn. R. 7005.0100, subp. 35a]
5.3.5	Hours of Operation: The Permittee shall maintain documentation on site that the unit is an emergency generator by design that qualifies under the U.S. EPA memorandum entitled "Calculating Potential to Emit (PTE) for Emergency Generators" dated September 6, 1995, that allows calculation of potential emissions based on 500 operating hours per year. [Minn. R. 7007.0800, subps. 4-5]
5.3.6	The Permittee shall keep records of fuel type and usage on a monthly basis. [Minn. R. 7007.0800, subp. 5]
5.3.7	EQUI 3 is a new affected source as defined under 40 CFR pt. 63, subp. ZZZZ, and the facility is an area source as defined at 40 CFR 63.2. The Permittee shall meet the requirements of 40 CFR pt. 63, subp. ZZZZ by meeting the requirements of 40 CFR pt. 60, subp. JJJJ. No further requirements of 40 CFR pt. 63, subp. ZZZZ apply to EQUI 3. [40 CFR 63.6590(c), Minn. R. 7011.8150]
5.3.8	The Permittee must limit Nitrogen Oxides <= 2.0 grams per horsepower-hour. [40 CFR 60.4233(e), 40 CFR 63.6590(c), 40 CFR pt. 60, subp. JJJJ(Table 1), Minn. R. 7011.2310, Minn. R. 7011.8150]
5.3.9	The Permittee must limit Carbon Monoxide <= 4.0 grams per horsepower-hour. [40 CFR 60.4233(e), 40 CFR 63.6590(c), 40 CFR pt. 60, subp. JJJJ(Table 1), Minn. R. 7011.2310, Minn. R. 7011.8150]
5.3.10	The Permittee must limit Volatile Organic Compounds <= 1.0 grams per horsepower-hour. [40 CFR 60.4233(e), 40 CFR 63.6590(c), 40 CFR pt. 60, subp. JJJJ(Table 1), Minn. R. 7011.2310, Minn. R. 7011.8150]
5.3.11	The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. JJJJ as follows: 40 CFR 60.4230(a)(4)(iv); 40 CFR 60.4230(a)(6);

Requirement number	Requirement and citation
	40 CFR 60.4233(e), as it pertains to stationary SI ICE meeting the criteria in the first sentence of this item; 40 CFR 60.4234; 40 CFR 60.4237(b); 40 CFR 60.4243(b)(1); 40 CFR 60.4243(a)(1); 40 CFR 60.4243(d); 40 CFR 60.4243(d)(1); 40 CFR 60.4243(d)(2); 40 CFR 60.4243(d)(2)(i); 40 CFR 60.4243(d)(3); 40 CFR 60.4243(e); 40 CFR 60.4245(a)(1)-(a)(3); 40 CFR 60.4245(b); 40 CFR 60.4245(e); 40 CFR 60.4245(g); 40 CFR 60.4246; 40 CFR 60.4248; and 40 CFR pt. 60, subp. JJJJ, Table 1. A copy of 40 CFR pt. 60, subp. JJJJ is included in Appendix C. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than three years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR 63.6590(c), 40 CFR pt. 60, subp. JJJJ, Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.2310, Minn. R. 7011.8150]
5.3.12	The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. A as follows: 40 CFR 60.1(a); 40 CFR 60.1(b); 40 CFR 60.1(c); 40 CFR 60.2; 40 CFR 60.3; 40 CFR 60.4; 40 CFR 60.7(a); 40 CFR 60.7(b); 40 CFR 60.8(a)-(f); 40 CFR 60.8(h); 40 CFR 60.8(i); 40 CFR 60.9; 40 CFR 60.11(a); 40 CFR 60.11(d); 40 CFR 60.11(f); 40 CFR 60.11(g); 40 CFR 60.12; and 40 CFR 60.19(a)-(c). A copy of 40 CFR pt. 60, subp. A is included in Appendix B. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if

Requirement number	Requirement and citation
	there are more than three years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR 60.4246(a), 40 CFR 63.6590(c), 40 CFR pt. 60, subp. A, 40 CFR pt. 60, subp. JJJ(Table 3), Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.0050, subp. 1(A), Minn. R. 7011.2310, Minn. R. 7011.8150, Minn. R. 7017.1010 & 7017.2015, subp. 2, Minn. R. 7019.0100]
EQUI 4	Natural Gas-Fired Turbine
5.4.1	The Permittee is authorized to construct and operate EQUI 4 meeting the following design requirements: ISO-Rated 7004 hp Solar Taurus 60-7800S combustion turbine. The authorization to construct expires 5 years after issuance of Air Emissions Permit No. 16300110-102. The units must meet all applicable permit requirements. [Minn. R. 7007.0800, subp. 2(A)]
5.4.2	The Permittee must limit emissions of Sulfur Dioxide $\leq$ 110 nanograms per joule (0.90 lb/MWh) gross output or 26 ng SO ₂ /J (0.060 lb SO ₂ /MMBtu) heat input. [40 CFR 60.4330a(a)]
5.4.3	The Permittee must limit emissions of Nitrogen Oxides $\leq$ 15 parts per million at 15 percent O ₂ or 24 ng/J (0.055 lb/MMBtu). This limit applies when turbine is firing natural gas at utilization rate $>$ 45 percent. [40 CFR 60.4320a(a), 40 CFR pt. 60, subp. KKKKa(Table 1)]
5.4.4	The Permittee must limit Other $\leq$ 10 scfm per seal. For the purpose of this requirement, other means the volumetric flow rate. If the individual seals are manifolded to a single open-ended vent line, the volumetric flow rate must not exceed the sum of the individual seals multiplied by 10 scfm. [40 CFR 60.5380b(a)(6)(i), 40 CFR 60.5410b(d)(6)(iii), 40 CFR 60.5415b(d)(2)]
5.4.5	Opacity $\leq$ 20 percent opacity once operating temperatures have been attained. [Minn. R. 7011.2300, subp. 1]
5.4.6	Sulfur Dioxide $\leq$ 0.0015 pounds per million Btu heat input. The potential to emit from the unit is 0.0014 lb/MMBtu due to equipment design and allowable fuels. [Minn. R. 7011.2300, subp. 2(B)]
5.4.7	Fuel type: Natural gas only, by design. [Minn. R. 7005.0100, subp. 35a]
5.4.8	The Permittee shall keep records of fuel type and usage on a monthly basis. [Minn. R. 7007.0800, subp. 5]
5.4.9	non-SoLoNO _x (low-load) Operating Hours $\leq$ 100 hours per year 12-month rolling sum in non-SoLoNO _x (Low-Load) operation mode to be calculated by the 15th day of each month for the previous 12-month period as described later in this permit. [Minn. R. 7007.0800, subp. 2(A)]
5.4.10	Startup and Shutdown (SUSD) events $\leq$ 1,400 times per year 12-month rolling sum in SUSD operation mode to be calculated by the 15th day of each month for the previous 12-month period as described later in this permit. The definition of SUSD is defined at 40 CFR 60.2. [Minn. R. 7007.0800, subp. 2(A)]
5.4.11	Low-temperature Operating Hours $\leq$ 720 hours per year 12-month rolling sum in low temperature (-20 deg F $<$ Temperature $<$ 0 deg F) operation mode to be calculated by the 15th day of each month for the previous 12-month period as described later in this permit. [Minn. R. 7007.0800, subp. 2(A)]
5.4.12	Hours: Daily Recordkeeping. On each day of operation, the Permittee must calculate, record, and maintain a record of the total hours of operation at each operation mode. This must be based on hour meter readings. [Minn. R. 7007.0800, subp. 2(A), Minn. R. 7007.0800, subps. 4-5]
5.4.13	Daily Recordkeeping. On each day of operation, the Permittee must calculate, record, and maintain a record of the total number of SUSD events. This must be based on operation logs. [Minn. R. 7007.0800, subp. 2(A), Minn. R. 7007.0800, subps. 4-5]
5.4.14	Hours: Monthly Recordkeeping. By the 15th of the month, the Permittee must calculate and record the following for each operation mode: 1) The total hours of operation for each mode for the previous calendar month using the daily data;

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	and 2) The 12-month rolling sum hours of operation for each mode by summing the monthly hours of operation for each operation mode for the previous 12 months. [Minn. R. 7007.0800, subps. 4-5]
5.4.15	Hours: Monthly Recordkeeping. By the 15th of the month, the Permittee must calculate and record the following: 1) The total number of SUSD events for the previous calendar month using the daily data; and 2) The 12-month rolling sum number of SUSD events for the previous 12-month period by summing the monthly number of SUSD events for the previous 12 months. [Minn. R. 7007.0800, subps. 4-5]
5.4.16	The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. KKKKa as follows: 40 CFR 60.4300a; 40 CFR 60.4305a(a)-(b); 40 CFR 60.4315a; 40 CFR 60.4320a(a); 40 CFR 60.4320a(b)(1); 40 CFR 60.4320a(b)(3); 40 CFR 60.4320a(d); 40 CFR 60.4330a(a)(1)-(2); 40 CFR 60.4333a(a); 40 CFR 60.4333a(b)(1)-(3); 40 CFR 60.4333a(c)(2); 40 CFR 60.4333a(d)(3); 40 CFR 60.4340a(a)(1); 40 CFR 60.4372a(a)-(b); 40 CFR 60.4375a(b); 40 CFR 60.4375a(e)-(j); 40 CFR 60.4385a(b); 40 CFR 60.4390a(a)-(b); 40 CFR 60.4390a(f); 40 CFR 60.4395a; 40 CFR 60.4400a(a)-(c); 40 CFR 60.4400a(d)(5); 40 CFR 60.4415a; 40 CFR 60.4420a; and 40 CFR pt. 60, subp. KKKKa, Table 1. A copy of 40 CFR pt. 60, subp. KKKKa is included in Appendix D. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than three years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR pt. 60, subp. KKKKa, Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500]
5.4.17	The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. A for 40 CFR pt. 60, subp. KKKKa as follows: 40 CFR 60.1; 40 CFR 60.2; Additional terms defined in 40 CFR 60.4420a 40 CFR 60.3; 40 CFR 60.4; 40 CFR 60.5;

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	40 CFR 60.6; 40 CFR 60.7; Only the requirements to submit the notifications in 40 CFR 60.7(a)(1) and (3) and to keep records of malfunctions in 40 CFR 60.7(b), if applicable 40 CFR 60.8(a); 40 CFR 60.8(b); 40 CFR 60.8(d)-(f); 40 CFR 60.9; 40 CFR 60.10; 40 CFR 60.12; 40 CFR 60.13(a)-(h); 40 CFR 60.13(j); 40 CFR 60.13(i); MPCA can approve alternative monitoring procedures or requirements 40 CFR 60.14; 40 CFR 60.15; 40 CFR 60.17; 40 CFR 60.18; and 40 CFR 60.19. A copy of 40 CFR pt. 60, subp. A is included in Appendix B. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than three years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR 60.4416a(a), 40 CFR pt. 60, subp. A, 40 CFR pt. 60, subp. KKKKa(Table 3), Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.0050, subp. 1(A), Minn. R. 7017.1010 & 7017.2015, subp. 2, Minn. R. 7019.0100]
5.4.18	The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. OOOOb as follows: 40 CFR 60.5360b; 40 CFR 60.5365b(b); 40 CFR 60.5370b(a)(7)(i); 40 CFR 60.5370b(b)-(c); 40 CFR 60.5371b; 40 CFR 60.5380b(a)(6); 40 CFR 60.5380b(a)(7)(iii); 40 CFR 60.5380b(a)(8); 40 CFR 60.5380b(b)-(d); 40 CFR 60.5386b; 40 CFR 60.5410b(d); 40 CFR 60.5415b(d)(2)-(4); 40 CFR 60.5420b(a)(1); 40 CFR 60.5420b(b)-(c); 40 CFR 60.5420b(c)(4)(i); 40 CFR 60.5420b(c)(4)(iii); 40 CFR 60.5420b(d)-(f); 40 CFR 60.5425b; and 40 CFR 60.5430b. A copy of 40 CFR pt. 60, subp. OOOOb is included in Appendix E.

Requirement number	Requirement and citation
	If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than three years remaining in the permit term, the Permittee must file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR pt. 60, subp. OOOOb, Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-1500]
5.4.19	The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. A for 40 CFR pt. 60, subp. OOOOb as follows: 40 CFR 60.1; 40 CFR 60.2; Additional terms defined in 40 CFR 60.5430b 40 CFR 60.3; 40 CFR 60.4; 40 CFR 60.5; 40 CFR 60.6; 40 CFR 60.7; Except that 40 CFR 60.7 only applies as specified in 40 CFR 60.5417b(c) and 40 CFR 60.5420b(a) 40 CFR 60.8; Except that the format and submittal of performance test report is described in 40 CFR 60.5420b(b) and (d). 40 CFR 60.9; 40 CFR 60.10; 40 CFR 60.12; 40 CFR 60.13; 40 CFR 60.14; To the extent any provision in 40 CFR 60.14 conflicts with specific provisions in subpart OOOOb, it is superseded by subpart OOOOb provisions. 40 CFR 60.15; 40 CFR 60.16; 40 CFR 60.17; 40 CFR 60.18; and 40 CFR 60.19; A copy of 40 CFR pt. 60, subp. A is included in Appendix B. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than three years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR 60.5425b, 40 CFR pt. 60, subp. A, 40 CFR pt. 60, subp. OOOOb(Table 5), Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.0050, subp. 1(A), Minn. R. 7017.1010 & 7017.2015, subp. 2, Minn. R. 7019.0100]
EQUI 5	Emergency Generator
5.5.1	The Permittee is authorized to construct and operate EQUI 5 meeting the following design requirements: 770 Hp/hr Cummins GTA 28E emergency generator. The authorization to construct expires 5 years after issuance of Air Emissions Permit No. 16300110-102. The units must meet all applicable permit requirements. [Minn. R. 7007.0800, subp. 2(A)]
5.5.2	The Permittee must limit Nitrogen Oxides <= 2.0 grams per horsepower-hour. [40 CFR 60.4233(e), 40 CFR 63.6590(c), 40 CFR pt. 60, subp. JJJJ(Table 1), Minn. R. 7011.2310, Minn. R. 7011.8150]
5.5.3	The Permittee must limit Carbon Monoxide <= 4.0 grams per horsepower-hour. [40 CFR 60.4233(e), 40 CFR 63.6590(c), 40 CFR pt. 60, subp. JJJJ(Table 1), Minn. R. 7011.2310, Minn. R. 7011.8150]

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5.5.4	The Permittee must limit Volatile Organic Compounds <= 1.0 grams per horsepower-hour. [40 CFR 60.4233(e), 40 CFR 63.6590(c), 40 CFR pt. 60, subp. JJJJ(Table 1), Minn. R. 7011.2310, Minn. R. 7011.8150]
5.5.5	Opacity <= 20 percent opacity once operating temperatures have been attained. [Minn. R. 7011.2300, subp. 1]
5.5.6	Sulfur Dioxide <= 0.0015 pounds per million Btu heat input. The potential to emit from the unit is 0.000588 lb/MMBtu due to equipment design and allowable fuels. [Minn. R. 7011.2300, subp. 2(B)]
5.5.7	Fuel type: Natural gas only, by design. [Minn. R. 7005.0100, subp. 35a]
5.5.8	Hours of Operation: The Permittee shall maintain documentation on site that the unit is an emergency generator by design that qualifies under the U.S. EPA memorandum entitled "Calculating Potential to Emit (PTE) for Emergency Generators" dated September 6, 1995, that allows calculation of potential emissions based on 500 operating hours per year. [Minn. R. 7007.0800, subps. 4-5]
5.5.9	The Permittee shall keep records of fuel type and usage on a monthly basis. [Minn. R. 7007.0800, subp. 5]
5.5.10	EQUI 5 is a new affected source as defined under 40 CFR pt. 63, subp. ZZZZ, and the facility is an area source as defined at 40 CFR 63.2. The Permittee shall meet the requirements of 40 CFR pt. 63, subp. ZZZZ by meeting the requirements of 40 CFR pt. 60, subp. JJJJ. No further requirements of 40 CFR pt. 63, subp. ZZZZ apply to EQUI 5. [40 CFR 63.6590(c), Minn. R. 7011.8150]
5.5.11	The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. JJJJ as follows: 40 CFR 60.4230(a)(4)(iv); 40 CFR 60.4230(a)(6); 40 CFR 60.4233(e), as it pertains to stationary SI ICE meeting the criteria in the first sentence of this item; 40 CFR 60.4234; 40 CFR 60.4237(a); 40 CFR 60.4243(b)(1); 40 CFR 60.4243(a)(1); 40 CFR 60.4243(d); 40 CFR 60.4243(d)(1); 40 CFR 60.4243(d)(2); 40 CFR 60.4243(d)(2)(i); 40 CFR 60.4243(d)(3); 40 CFR 60.4243(e); 40 CFR 60.4245(a)(1)-(3); 40 CFR 60.4245(b); 40 CFR 60.4245(e); 40 CFR 60.4245(g); 40 CFR 60.4245(j); 40 CFR 60.4246(a); 40 CFR 60.4248; and 40 CFR pt. 60, subp JJJJ Table 1. A copy of 40 CFR pt. 60, subp. JJJJ is included in Appendix C. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than three years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR 63.6590(c), 40 CFR pt. 60, subp. JJJJ, Minn. R. 7007.0400, subp.

Requirement number	Requirement and citation
	3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.2310, Minn. R. 7011.8150]
5.5.12	The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. A as follows: 40 CFR 60.1; 40 CFR 60.2; 40 CFR 60.3; 40 CFR 60.4; 40 CFR 60.5; 40 CFR 60.6; 40 CFR 60.7; 40 CFR 60.8; 40 CFR 60.9; 40 CFR 60.10; 40 CFR 60.11; 40 CFR 60.12; 40 CFR 60.14; 40 CFR 60.15; 40 CFR 60.16; 40 CFR 60.17; 40 CFR 60.18; and 40 CFR 60.19. A copy of 40 CFR pt. 60, subp. A is included in Appendix B. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than three years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR 60.4246(a), 40 CFR 63.6590(c), 40 CFR pt. 60, JJJJ(Table 3), 40 CFR pt. 60, subp. A, Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.0050, subp. 1(A), Minn. R. 7011.2310, Minn. R. 7011.8150, Minn. R. 7017.1010 & 7017.2015, subp. 2, Minn. R. 7019.0100]
FUGI 1	Fugitive emissions components
5.6.1	The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. OOOOb as follows: 40 CFR 60.5360b; 40 CFR 60.5365b(i)(3); 40 CFR 60.5370b(b)-(c); 40 CFR 60.5371b; 40 CFR 60.5397b(a)-(g)(1); 40 CFR 60.5397b(g)(1)(v); 40 CFR 60.5397b(g)(2)-(4); 40 CFR 60.5397b(h)-(k); 40 CFR 60.5410b(k); 40 CFR 60.5415b(l); 40 CFR 60.5420b(a)(1); 40 CFR 60.5420b(b)-(c); 40 CFR 60.5420b(c)(14)(i); 40 CFR 60.5420b(c)(14)(iv)-(vi); 40 CFR 60.5420b(c)(14)(viii); 40 CFR 60.5420b(d)-(f);

Requirement number	Requirement and citation
	40 CFR 60.5425b; and 40 CFR 60.5430b. A copy of 40 CFR pt. 60, subp. OOOOb is included in Appendix E. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than three years remaining in the permit term, the Permittee must file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR pt. 60, subp. OOOOb, Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-1500]
5.6.2	The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. A for 40 CFR pt. 60, subp. OOOOb as follows: 40 CFR 60.1; 40 CFR 60.2; Additional terms defined in 40 CFR 60.5430b 40 CFR 60.3; 40 CFR 60.4; 40 CFR 60.5; 40 CFR 60.6; 40 CFR 60.7; Except that 40 CFR 60.7 only applies as specified in 40 CFR 60.5417b(c) and 40 CFR 60.5420b(a) 40 CFR 60.8; Except that the format and submittal of performance test report is described in 40 CFR 60.5420b(b) and (d). 40 CFR 60.9; 40 CFR 60.10; 40 CFR 60.12; 40 CFR 60.13; 40 CFR 60.14; To the extent any provision in 40 CFR 60.14 conflicts with specific provisions in subpart OOOOb, it is superseded by subpart OOOOb provisions. 40 CFR 60.15; 40 CFR 60.16; 40 CFR 60.17; 40 CFR 60.18; and 40 CFR 60.19; A copy of 40 CFR pt. 60, subp. A is included in Appendix B. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than three years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR 60.5425b, 40 CFR pt. 60, subp. A, 40 CFR pt. 60, subp. OOOOb(Table 5), Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.0050, subp. 1(A), Minn. R. 7017.1010 & 7017.2015, subp. 2, Minn. R. 7019.0100]
FUGI 4	Compressor Blowdown
5.7.1	Opacity <= 20 percent opacity. [Minn. R. 7011.0715, subp. 1(B)]
5.7.2	Particulate Matter <= 0.30 grains per dry standard cubic foot of exhaust gas unless required to further reduce emissions to comply with the less stringent limit of either Minn. R. 7011.0730 or Minn. R. 7011.0735. [Minn. R. 7011.0715, subp. 1(A)]

6. Submittal/action requirements

This section lists most of the submittals required by this permit. Please note that some submittal requirements may appear in the Limits and Other Requirements section, or, if applicable, within a Compliance Schedule section.

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TFAC 1	Northern Natural Gas Co - Hugo
6.1.1	The Permittee must submit a semiannual deviations report : Due semiannually, by the 30th of January and July. The first semiannual report submitted by the Permittee must cover the calendar half-year in which the permit is issued. The first report of each calendar year covers January 1 - June 30. The second report of each calendar year covers July 1 - December 31. Submit this on form DRF-2 (Deviation Reporting Form). If no deviations have occurred, submit the signed report certifying that there were no deviations. [Minn. R. 7007.0800, subp. 6(B)(2)]
6.1.2	The Permittee must submit a compliance certification : Due annually, by the 31st of January (for the previous calendar year). Submit this on form CR-04 (Annual Compliance Certification Report). This report covers all deviations experienced during the calendar year. If no deviations have occurred, submit the signed report certifying that there were no deviations. [Minn. R. 7007.0800, subp. 6(D)]
EQUI 1	Gas Turbine Compressor
6.2.1	The Permittee shall submit a notification of equipment removal/dismantlement: Due 15 calendar days after Equipment Removal and/or Dismantlement Date. This notification shall specify which Subject Items (by ID#) were removed and on what date. [Minn. R. 7007.0800, subp. 2(A)]
EQUI 3	Back up Generator
6.3.1	The Permittee shall submit a notification of equipment removal/dismantlement: Due 15 calendar days after Equipment Removal and/or Dismantlement Date. This notification shall specify which Subject Items (by ID#) were removed and on what date. [Minn. R. 7007.0800, subp. 2(A)]
6.3.2	If EQUI 3 operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in 40 CFR 60.4243(d)(2)(ii) and (iii) or that operates for the purposes specified in 40 CFR 60.4243(d)(3)(i), then the following applies: The Permittee shall submit an annual report for each calendar year no later than March 31 of the following calendar year. The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (www.epa.gov/cdx). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in 40 CFR 60.4. [40 CFR 60.4245(e)(2), 40 CFR 60.4245(e)(3), 40 CFR 63.6590(c)(1), Minn. R. 7011.2310, Minn. R. 7011.8150]
EQUI 4	Natural Gas-Fired Turbine
6.4.1	The Permittee shall submit a notification of the date construction began: Due 30 calendar days after Date of Construction Start (or reconstruction). Submit the name and number of the Subject Item and the date construction began. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]
6.4.2	The Permittee shall submit a notification of the actual date of initial startup: Due 15 calendar days after Initial Startup Date. Submit the name and number of the Subject Item and the date of startup. Startup is as defined in Minn. R. 7005.0100, subp. 42a. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]
6.4.3	The Permittee must submit a notification: due 30 days prior to any performance test. [40 CFR 60.4375a(b), 40 CFR 60.8(d), Minn. R. 7017.2020, subp. 1]

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6.4.4	Within 60 days after the date of completing each performance test or continuous emissions monitoring systems (CEMS) performance evaluation that includes a RATA, the Permittee must submit the results following the procedures specified in paragraph 40 CFR 60.4375(g). [40 CFR 60.4375a(e)]
6.4.5	The Permittee must submit initial annual report: Due no later than 90 days after the end of the initial compliance period as determined according to 40 CFR 60.5410b. Subsequent annual reports are due no later than the same date each year as the initial annual report. The report must contain the applicable information identified in 40 CFR 60.5420b(b)(1) and (5), and (b)(11), and (13), as applicable. [40 CFR 60.5380b(d), 40 CFR 60.5410b(d)(7), 40 CFR 60.5415b(d)(3), 40 CFR 60.5420b(b), 40 CFR 60.5420b(d)]
6.4.6	The Permittee must conduct first volumetric flow rate measurement from the centrifugal compressor equipped with a dry seal before 8,760 hours of operation after startup. The Permittee must determine the volumetric flow rate as specified in 40 CFR 60.5380b(a)(7)(iii). [40 CFR 60.5380b(a)(6)(ii), 40 CFR 60.5380b(a)(7)(iii)]
6.4.7	The Permittee must conduct subsequent volumetric flow rate measurements from the centrifugal compressor equipped with dry seals before 8,760 hours of operation after the previous measurement which demonstrated compliance with the 10 scfm volumetric flow rate per seal. The Permittee must determine the volumetric flow rate as specified in 40 CFR 60.5380b(a)(7)(iii). [40 CFR 60.5380b(a)(6)(iii), 40 CFR 60.5380b(a)(7)(iii)]
6.4.8	Nitrogen Oxides: Initial performance test: The Permittee shall conduct a performance test due 180 calendar days after Initial Startup Date to measure emissions of NO_x in accordance with 40 CFR 60.8 and 40 CFR 60.4400a. The performance test must be done at any load condition within +/-2.5 percent of 100 percent of the base load rating. The Permittee may perform testing at the highest achievable load point, if at least 75 percent of the base load rating cannot be achieved in practice. The Permittee must conduct three separate test runs for each performance test. The minimum time per run is 20 minutes. [40 CFR 60.4333a(b)(1), 40 CFR 60.4400a(a)-(c), 40 CFR 60.4400a(d)(5), 40 CFR 60.8, Minn. R. 7011.2020, subp. 1]
6.4.9	Nitrogen Oxides: Performance Test. The Permittee must conduct performance tests: Due within 12 calendar months of the date that the previous performance test was conducted to measure emissions of NO_x in accordance with 40 CFR 60.8 and the procedures in 40 CFR 60.4400a. The performance test must be done at any load condition within +/-2.5 percent of 100 percent of the base load rating. The Permittee may perform testing at the highest achievable load point, if at least 75 percent of the base load rating cannot be achieved in practice. The Permittee must conduct three separate test runs for each performance test. The minimum time per run is 20 minutes. If the NO_x emission result from the most recent performance test is less than or equal to 75 percent of the NO_x emissions standard for the stationary combustion turbine, the Permittee may reduce the frequency of subsequent performance tests to 26 calendar months following the date the previous performance test was conducted. If the results of any subsequent performance test exceed 75 percent of the NO_x emission standard for the stationary combustion turbine, the Permittee must resume 14-calendar-month performance testing. [40 CFR 60.4333a(b)(1)-(3), 40 CFR 60.4400a(a), 40 CFR 60.4400a(b)-(c), 40 CFR 60.4400a(d)(5), 40 CFR 60.8, Minn. R. 7011.2020, subp. 1]
6.4.10	Sulfur Dioxide: The Permittee must conduct a performance test due 180 calendar days after Initial Startup Date to measure emissions of SO ₂ in accordance with 40 CFR 60.8 and 40 CFR 60.4415a. The performance test shall be conducted at worst-case conditions as defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Method 6C, or other method approved by MPCA in the performance test plan approval. [40 CFR 60.4333a(d)(3), 40 CFR 60.4415a, 40 CFR 60.8, Minn. R. 7011.2020, subp. 1]

Requirement number	Requirement and citation
EQUI 5	Emergency Generator
6.5.1	The Permittee shall submit a notification of the date construction began: Due 30 calendar days after Date of Construction Start (or reconstruction). Submit the name and number of the Subject Item and the date construction began. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]
6.5.2	The Permittee shall submit a notification of the actual date of initial startup: Due 15 calendar days after Initial Startup Date. Submit the name and number of the Subject Item and the date of startup. Startup is as defined in Minn. R. 7005.0100, subp. 42a. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]
FUGI 1	Fugitive emissions components
6.6.1	The Permittee must submit initial annual report: Due no later than 90 days after the end of the initial compliance period as determined according to 40 CFR 60.5410b. Subsequent annual reports are due no later than the same date each year as the initial annual report. The report must contain the applicable information identified in 40 CFR 60.5420b(b). [40 CFR 60.5410b(k)(4), 40 CFR 60.5415b(l)(3), 40 CFR 60.5420b(b), 40 CFR 60.5420b(d)]

7. Appendices

Appendix A. Insignificant activities and general applicable requirements

The table below lists the insignificant activities that are currently at the Facility and their associated general applicable requirements.

Minn. R.	Rule description of the activity	General applicable requirement
Minn. R. 7007.1300, subp. 3(F)	Individual units with potential emissions less than 2000 lb/year of certain pollutants. <i>The Permittee has one 0.3 MMBtu/hr natural gas heater and 8 space heaters with total combined capacity of 0.65 MMBtu/hr.</i>	PM <= 0.4 lb/MMBtu Opacity <= 20%, with exceptions (Minn. R. 7011.0515)

Appendix B. 40 CFR Part 60, Subpart A—General Provisions

§ 60.1 Applicability.

- (a) Except as provided in subparts B, Ba, and C of this part, the provisions of this part apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication in this part of any standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility.
- (b) Any new or revised standard of performance promulgated pursuant to section 111(b) of the Act shall apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication in this part of such new or revised standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility.
- (c) In addition to complying with the provisions of this part, the owner or operator of an affected facility may be required to obtain an operating permit issued to stationary sources by an authorized State air pollution control agency or by the Administrator of the U.S. Environmental Protection Agency (EPA) pursuant to Title V of the Clean Air Act (Act) as amended November 15, 1990 (42 U.S.C. 7661). For more information about obtaining an operating permit see part 70 of this chapter.
- (d) *Site-specific standard for Merck & Co., Inc.'s Stonewall Plant in Elkton, Virginia.*
- (1) This paragraph applies only to the pharmaceutical manufacturing facility, commonly referred to as the Stonewall Plant, located at Route 340 South, in Elkton, Virginia ("site").
- (2) Except for compliance with 40 CFR 60.49b(u), the site shall have the option of either complying directly with the requirements of this part, or reducing the site-wide emissions caps in accordance with the procedures set forth in a permit issued pursuant to 40 CFR 52.2454. If the site chooses the option of reducing the site-wide emissions caps in accordance with the procedures set forth in such permit, the requirements of such permit shall apply in lieu of the otherwise applicable requirements of this part.
- (3) Notwithstanding the provisions of paragraph (d)(2) of this section, for any provisions of this part except for Subpart Kb, the owner/operator of the site shall comply with the applicable provisions of this part if the Administrator determines that compliance with the provisions of this part is necessary for achieving the objectives of the regulation and the Administrator notifies the site in accordance with the provisions of the permit issued pursuant to 40 CFR 52.2454.

§ 60.2 Definitions.

The terms used in this part are defined in the Act or in this section as follows:

Act means the Clean Air Act (42 U.S.C. 7401 *et seq.*)

Administrator means the Administrator of the Environmental Protection Agency or his authorized representative.

Affected facility means, with reference to a stationary source, any apparatus to which a standard is applicable.

Alternative method means any method of sampling and analyzing for an air pollutant which is not a reference or equivalent method but which has been demonstrated to the Administrator's satisfaction to, in specific cases, produce results adequate for his determination of compliance.

Approved permit program means a State permit program approved by the Administrator as meeting the requirements of part 70 of this chapter or a Federal permit program established in this chapter pursuant to Title V of the Act (42 U.S.C. 7661).

Capital expenditure means an expenditure for a physical or operational change to an existing facility which exceeds the product of the applicable "annual asset guideline repair allowance percentage" specified in the latest edition of

Internal Revenue Service (IRS) Publication 534 and the existing facility's basis, as defined by section 1012 of the Internal Revenue Code. However, the total expenditure for a physical or operational change to an existing facility must not be reduced by any "excluded additions" as defined in IRS Publication 534, as would be done for tax purposes.

Clean coal technology demonstration project means a project using funds appropriated under the heading 'Department of Energy-Clean Coal Technology', up to a total amount of \$2,500,000,000 for commercial demonstrations of clean coal technology, or similar projects funded through appropriations for the Environmental Protection Agency.

Commenced means, with respect to the definition of *new source* in section 111(a)(2) of the Act, that an owner or operator has undertaken a continuous program of construction or modification or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction or modification.

Construction means fabrication, erection, or installation of an affected facility.

Continuous monitoring system means the total equipment, required under the emission monitoring sections in applicable subparts, used to sample and condition (if applicable), to analyze, and to provide a permanent record of emissions or process parameters.

Electric utility steam generating unit means any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is also considered in determining the electrical energy output capacity of the affected facility.

Equivalent method means any method of sampling and analyzing for an air pollutant which has been demonstrated to the Administrator's satisfaction to have a consistent and quantitatively known relationship to the reference method, under specified conditions.

Excess Emissions and Monitoring Systems Performance Report is a report that must be submitted periodically by a source in order to provide data on its compliance with stated emission limits and operating parameters, and on the performance of its monitoring systems.

Existing facility means, with reference to a stationary source, any apparatus of the type for which a standard is promulgated in this part, and the construction or modification of which was commenced before the date of proposal of that standard; or any apparatus which could be altered in such a way as to be of that type.

Force majeure means, for purposes of § 60.8, an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents the owner or operator from complying with the regulatory requirement to conduct performance tests within the specified timeframe despite the affected facility's best efforts to fulfill the obligation. Examples of such events are acts of nature, acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility.

Isokinetic sampling means sampling in which the linear velocity of the gas entering the sampling nozzle is equal to that of the undisturbed gas stream at the sample point.

Issuance of a part 70 permit will occur, if the State is the permitting authority, in accordance with the requirements of part 70 of this chapter and the applicable, approved State permit program. When the EPA is the permitting authority, issuance of a Title V permit occurs immediately after the EPA takes final action on the final permit.

Malfunction means 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.

Modification means any physical change in, or change in the method of operation of, an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted into the atmosphere by that facility or which results in the emission of any air pollutant (to which a standard applies) into the atmosphere not previously emitted.

Monitoring device means the total equipment, required under the monitoring of operations sections in applicable subparts, used to measure and record (if applicable) process parameters.

Nitrogen oxides means all oxides of nitrogen except nitrous oxide, as measured by test methods set forth in this part.

One-hour period means any 60-minute period commencing on the hour.

Opacity means the degree to which emissions reduce the transmission of light and obscure the view of an object in the background.

Owner or operator means any person who owns, leases, operates, controls, or supervises an affected facility or a stationary source of which an affected facility is a part.

Part 70 permit means any permit issued, renewed, or revised pursuant to part 70 of this chapter.

Particulate matter means any finely divided solid or liquid material, other than uncombined water, as measured by the reference methods specified under each applicable subpart, or an equivalent or alternative method.

Permit program means a comprehensive State operating permit system established pursuant to title V of the Act (42 U.S.C. 7661) and regulations codified in part 70 of this chapter and applicable State regulations, or a comprehensive Federal operating permit system established pursuant to title V of the Act and regulations codified in this chapter.

Permitting authority means:

- (1) The State air pollution control agency, local agency, other State agency, or other agency authorized by the Administrator to carry out a permit program under part 70 of this chapter; or
- (2) The Administrator, in the case of EPA-implemented permit programs under title V of the Act (42 U.S.C. 7661).

Proportional sampling means sampling at a rate that produces a constant ratio of sampling rate to stack gas flow rate.

Reactivation of a very clean coal-fired electric utility steam generating unit means any physical change or change in the method of operation associated with the commencement of commercial operations by a coal-fired utility unit after a period of discontinued operation where the unit:

- (1) Has not been in operation for the two-year period prior to the enactment of the Clean Air Act Amendments of 1990, and the emissions from such unit continue to be carried in the permitting authority's emissions inventory at the time of enactment;
- (2) Was equipped prior to shut-down with a continuous system of emissions control that achieves a removal efficiency for sulfur dioxide of no less than 85 percent and a removal efficiency for particulates of no less than 98 percent;
- (3) Is equipped with low-NO_x burners prior to the time of commencement of operations following reactivation; and
- (4) Is otherwise in compliance with the requirements of the Clean Air Act.

Reference method means any method of sampling and analyzing for an air pollutant as specified in the applicable subpart.

Repowering means replacement of an existing coal-fired boiler with one of the following clean coal technologies: atmospheric or pressurized fluidized bed combustion, integrated gasification combined cycle, magnetohydrodynamics, direct and indirect coal-fired turbines, integrated gasification fuel cells, or as determined by the Administrator, in consultation with the Secretary of Energy, a derivative of one or more of these technologies, and any other technology capable of controlling multiple combustion emissions simultaneously with improved boiler or generation efficiency and with significantly greater waste reduction relative to the performance of technology in widespread commercial use as of November 15, 1990. Repowering shall also include any oil and/or gas-fired unit which has been awarded clean coal technology demonstration funding as of January 1, 1991, by the Department of Energy.

Run means the net period of time during which an emission sample is collected. Unless otherwise specified, a run may be either intermittent or continuous within the limits of good engineering practice.

Shutdown means the cessation of operation of an affected facility for any purpose.

Six-minute period means any one of the 10 equal parts of a one-hour period.

Standard means a standard of performance proposed or promulgated under this part.

Standard conditions means a temperature of 293 K (68F) and a pressure of 101.3 kilopascals (29.92 in Hg).

Startup means the setting in operation of an affected facility for any purpose.

State means all non-Federal authorities, including local agencies, interstate associations, and State-wide programs, that have delegated authority to implement:

- (1) The provisions of this part; and/or
- (2) the permit program established under part 70 of this chapter. The term State shall have its conventional meaning where clear from the context.

Stationary source means any building, structure, facility, or installation which emits or may emit any air pollutant.

Title V permit means any permit issued, renewed, or revised pursuant to Federal or State regulations established to implement title V of the Act (42 U.S.C. 7661). A title V permit issued by a State permitting authority is called a part 70 permit in this part.

Volatile Organic Compound means any organic compound which participates in atmospheric photochemical reactions; or which is measured by a reference method, an equivalent method, an alternative method, or which is determined by procedures specified under any subpart.

§ 60.3 Units and abbreviations.

Used in this part are abbreviations and symbols of units of measure. These are defined as follows:

(a) System International (SI) units of measure:

A—ampere

g—gram

Hz—hertz

J—joule

K—degree Kelvin

kg—kilogram

m—meter

m³—cubic meter

mg—milligram—10⁻³ gram

mm—millimeter—10⁻³ meter

Mg—megagram—10⁶ gram

mol—mole

N—newton

ng—nanogram—10⁻⁹ gram

nm—nanometer—10⁻⁹ meter

Pa—pascal

s—second

V—volt

W—watt

Ω—ohm

μg—microgram—10⁻⁶ gram

(b) Other units of measure:

Btu—British thermal unit

°C—degree Celsius (centigrade)

cal—calorie

cfm—cubic feet per minute

cu ft—cubic feet

dcf—dry cubic feet

dcm—dry cubic meter

dscf—dry cubic feet at standard conditions

dscm—dry cubic meter at standard conditions

eq—equivalent

°F—degree Fahrenheit

ft—feet

gal—gallon

gr—grain

g-eq—gram equivalent

hr—hour

in—inch

k—1,000

l—liter

lpm—liter per minute

lb—pound

meq—milliequivalent

min—minute

ml—milliliter

mol. wt.—molecular weight

ppb—parts per billion

ppm—parts per million

psia—pounds per square inch absolute

psig—pounds per square inch gage

°R—degree Rankine

scf—cubic feet at standard conditions

scfh—cubic feet per hour at standard conditions

scm—cubic meter at standard conditions

sec—second

sq ft—square feet

std—at standard conditions

(c) Chemical nomenclature:

CdS—cadmium sulfide

CO—carbon monoxide

CO₂—carbon dioxide

HCl—hydrochloric acid

Hg—mercury

H₂O—water

H₂S—hydrogen sulfide

H₂SO₄—sulfuric acid

N₂—nitrogen

NO—nitric oxide

NO₂—nitrogen dioxide

NO_x—nitrogen oxides

O₂—oxygen

SO₂—sulfur dioxide

SO₃—sulfur trioxide

SO_x—sulfur oxides

(d) Miscellaneous:

A.S.T.M.—American Society for Testing and Materials

§ 60.4 Address.

- (a) All requests, reports, applications, submittals, and other communications to the Administrator pursuant to this part shall be submitted in duplicate to the appropriate Regional Office of the U.S. Environmental Protection Agency to the attention of the Director of the Division indicated in the following table.

Table 1 to Paragraph (a)		
Region	Address	State
I	Director, Enforcement and Compliance Assurance Division, U.S. EPA Region I, 5 Post Office Square—Suite 100 (04-2), Boston, MA 02109-3912, Attn: Air Compliance Clerk	Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont.
II	Director, Air and Waste Management Division, U.S. Environmental Protection Agency, Federal Office Building, 26 Federal Plaza (Foley Square), New York, NY 10278	New Jersey, New York, Puerto Rico, Virgin Islands.
III	Director, Air Protection Division, Mail Code 3AP00, 1650 Arch Street, Philadelphia, PA 19103-2029	Delaware, District of Columbia, Maryland, Pennsylvania, Virginia, West Virginia.
IV	Director, Air and Radiation Division, 61 Forsyth Street SW, Atlanta, Georgia 30303-8960	Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee.
V	Director, Air and Radiation Division, U.S. Environmental Protection Agency, 77 West Jackson Boulevard, Chicago, IL 60604-3590	Illinois, Indiana, Michigan, Minnesota, Ohio, Wisconsin.
VI	Director; Enforcement and Compliance Assurance Division; U.S. Environmental Protection Agency, 1201 Elm Street, Suite 500, Mail Code 6ECD, Dallas, Texas 75270-2102	Arkansas, Louisiana, New Mexico, Oklahoma, Texas.
VII	Director, Air and Waste Management Division, 11201 Renner Boulevard, Lenexa, Kansas 66219	Iowa, Kansas, Missouri, Nebraska.
VIII	Director, Air and Toxics Technical Enforcement Program, Office of	Colorado, Montana, North Dakota, South Dakota, Utah, Wyoming.

Table 1 to Paragraph (a)		
Region	Address	State
	Enforcement, Compliance and Environmental Justice, Mail Code 8ENF-AT, 1595 Wynkoop Street, Denver, CO 80202-1129	
IX	Director, Enforcement and Compliance Assurance Division (ENF 2-1), U.S. Environmental Protection Agency Region IX, 75 Hawthorne Street, San Francisco, CA 94105	Arizona, California, Hawaii and Nevada; the territories of American Samoa and Guam; the Commonwealth of the Northern Mariana Islands; the territories of Baker Island, Howland Island, Jarvis Island, Johnston Atoll, Kingman Reef, Midway Atoll, Palmyra Atoll, and Wake Islands; and certain U.S. Government activities in the freely associated states of the Republic of the Marshall Islands, the Federated States of Micronesia, and the Republic of Palau.
X	Director, Air and Waste Management Division, U.S. Environmental Protection Agency, 1200 Sixth Avenue, Seattle, WA 98101	Alaska, Oregon, Idaho, Washington.

(b) Section 111(c) directs the Administrator to delegate to each State, when appropriate, the authority to implement and enforce standards of performance for new stationary sources located in such State. All information required to be submitted to EPA under paragraph (a) of this section, must also be submitted to the appropriate State Agency of any State to which this authority has been delegated (provided, that each specific delegation may except sources from a certain Federal or State reporting requirement). The appropriate mailing address for those States whose delegation request has been approved is as follows:

(1) [Reserved]

(2) State of Alabama: Alabama Department of Environmental Management, P.O. Box 301463, Montgomery, Alabama 36130-1463.

(3) State of Alaska, Department of Environmental Conservation, Pouch O, Juneau, AK 99811.

(4) Arizona:

Arizona Department of Environmental Quality, Suite #160, 1110 West Washington Street, Phoenix, AZ 85007.

Maricopa County Air Quality Department, 301 West Jefferson Street, Phoenix, AZ 85003.

Pima County Department of Environmental Quality, 33 North Stone Avenue, Suite 700, Tucson, AZ 85701.

Pinal County Air Quality Department, 31 North Pinal Street, Building F, Florence, AZ 85132.

Note 1 to paragraph (b)(4):

For tables listing the delegation status of agencies in Region IX, see paragraph (d) of this section.

(5) State of Arkansas: Chief, Division of Air Pollution Control, Arkansas Department of Pollution Control and Ecology, 8001 National Drive, P.O. Box 9583, Little Rock, AR 72209.

(6) California:

Amador Air District, 810 Court Street, Jackson, CA 95642.

Antelope Valley Air Quality Management District, 2551 W Avenue H, Lancaster, CA 93536.

Bay Area Air Quality Management District, 375 Beale Street, Suite 600, San Francisco, CA 94105.

Butte County Air Quality Management District, 629 Entler Avenue, Suite 15, Chico, CA 95928.

Calaveras County Air Pollution Control District, 891 Mountain Ranch Road, Building E, San Andreas, CA 95249.

Colusa County Air Pollution Control District, 100 Sunrise Blvd., Suite A, Colusa, CA 95932-3246.

El Dorado County Air Quality Management District, 330 Fair Lane, Placerville, CA 95667-4100.

Eastern Kern Air Pollution Control District, 2700 "M" Street, Suite 302, Bakersfield, CA 93301-2370.

Feather River Air Quality Management District, 541 Washington Avenue, Yuba City, CA 95991.

Glenn County Air Pollution Control District, 720 N Colusa Street, P.O. Box 351, Willows, CA 95988-0351.

Great Basin Unified Air Pollution Control District, 157 Short Street, Bishop, CA 93514-3537.

Imperial County Air Pollution Control District, 150 South Ninth Street, El Centro, CA 92243-2839.

Lake County Air Quality Management District, 2617 S Main St., Lakeport, CA 95453-5405.

Lassen County Air Pollution Control District, 720 South St., Susanville, CA 96130.

Mariposa County Air Pollution Control District, P.O. Box 5, Mariposa, CA 95338.

Mendocino County Air Quality Management District, 306 E Gobbi Street, Ukiah, CA 95482-5511.

Modoc County Air Pollution Control District, 202 W 4th Street, Alturas, CA 96101.

Mojave Desert Air Quality Management District, 14306 Park Avenue, Victorville, CA 92392-2310.

Monterey Bay Air Resources District, 24580 Silver Cloud Court, Monterey, CA 93940.

North Coast Unified Air Quality Management District, 707 L Street, Eureka, CA 95501-3327.

Northern Sierra Air Quality Management District, 200 Litton Drive, Suite 320, Grass Valley, CA 95945-2509.

Northern Sonoma County Air Pollution Control District, 150 Matheson Street, Healdsburg, CA 95448-4908.

Placer County Air Pollution Control District, 110 Maple Street, Auburn, CA 95603.

Sacramento Metropolitan Air Quality Management District, 777 12th Street, Suite 300, Sacramento, CA 95814-1908.

San Diego County Air Pollution Control District, 10124 Old Grove Road, San Diego, CA 92131-1649.

San Joaquin Valley Air Pollution Control District, 1990 E Gettysburg, Fresno, CA 93726.

San Luis Obispo County Air Pollution Control District, 3433 Roberto Court, San Luis Obispo, CA 93401-7126.

Santa Barbara County Air Pollution Control District, 260 North San Antonio Road, Suite A, Santa Barbara, CA 93110-1315.

Shasta County Air Quality Management District, 1855 Placer Street, Suite 101, Redding, CA 96001-1759.

Siskiyou County Air Pollution Control District, 525 So. Foothill Drive, Yreka, CA 96097-3036.

South Coast Air Quality Management District, 21865 Copley Drive, Diamond Bar, CA 91765-4182.

Tehama County Air Pollution Control District, P.O. Box 1169 (1834 Walnut Street), Red Bluff, CA 96080-0038.

Tuolumne County Air Pollution Control District, 2 South Green St., Sonora, CA 95370-4618.

Ventura County Air Pollution Control District, 4567 Telephone Road, 2nd Floor, Ventura, CA 93003-5417.

Yolo-Solano Air Quality Management District, 1947 Galileo Court, Suite 103, Davis, CA 95618.

Note 2 to paragraph (b)(6):

For tables listing the delegation status of agencies in Region IX, see paragraph (d) of this section.

(7) State of Colorado, Department of Public Health and Environment, 4300 Cherry Creek Drive South, Denver, CO 80222-1530.

Note:

For a table listing Region VIII's NSPS delegation status, see paragraph (c) of this section.

(8) State of Connecticut, Compliance Analysis and Coordination Unit, Bureau of Air Management, Department of Energy and Environmental Protection, 79 Elm Street, 5th Floor, Hartford, CT 06106-5127.

(9) State of Delaware, Department of Natural Resources & Environmental Control, 89 Kings Highway, P.O. Box 1401, Dover, Delaware 19903.

(10) District of Columbia, Department of Public Health, Air Quality Division, 51 N Street, NE., Washington, DC 20002.

(11) State of Florida: Florida Department of Environmental Protection, Division of Air Resources Management, 2600 Blair Stone Road, MS 5500, Tallahassee, Florida 32399-2400.

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

(13) Hawaii:

Clean Air Branch, Hawaii Department of Health, 2827 Waimano Home Road, #130 Pearl City, HI 96782.

Note 4 to paragraph (b)(13):

For tables listing the delegation status of agencies in Region IX, see paragraph (d) of this section.

(14) State of Idaho, Department of Health and Welfare, Statehouse, Boise, ID 83701.

(15) State of Illinois: Illinois Environmental Protection Agency, 1021 North Grand Avenue East, Springfield, Illinois 62794.

(16) State of Indiana: Indiana Department of Environmental Management, Office of Air Quality, 100 North Senate Avenue, Indianapolis, Indiana 46204.

(17) State of Iowa: Iowa Department of Natural Resources, Environmental Protection Division, Air Quality Bureau, 7900 Hickman Road, Suite 1, Urbandale, IA 50322.

(18) State of Kansas: Kansas Department of Health and Environment, Bureau of Air and Radiation, 1000 S.W. Jackson, Suite 310, Topeka, KS 66612-1366.

(19) Commonwealth of Kentucky: Kentucky Department for Environmental Protection, Division for Air Quality, 300 Sower Boulevard, 2nd Floor, Frankfort, Kentucky 40601 or local agency, Louisville Metro Air Pollution Control District, 701 W. Ormsby Ave., Suite 303, Louisville, Kentucky 40203.

(20) State of Louisiana: Louisiana Department of Environmental Quality, P.O. Box 4301, Baton Rouge, Louisiana 70821-4301.

Note:

For a list of delegated standards for Louisiana (excluding Indian country), see paragraph (e)(2) of this section.

(21) State of Maine, Maine Department of Environmental Protection, Bureau of Air Quality, 17 State House Station, Augusta, ME 04333-0017.

(22) State of Maryland, Department of the Environment, 1800 Washington Boulevard, Suite 705, Baltimore, Maryland 21230.

(23) Commonwealth of Massachusetts, Massachusetts Department of Environmental Protection, Division of Air and Climate Programs, One Winter Street, Boston, MA 02108.

(24) State of Michigan: Michigan Department of Natural Resources and Environment, Air Quality Division, P.O. Box 30028, Lansing, Michigan 48909.

(25) State of Minnesota: Minnesota Pollution Control Agency, Division of Air Quality, 520 Lafayette Road North, St. Paul, Minnesota 55155.

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

(27) State of Missouri: Missouri Department of Natural Resources, Division of Environmental Quality, P.O. Box 176, Jefferson City, MO 65102.

(28) State of Montana, Department of Environmental Quality, 1520 E. 6th Ave., PO Box 200901, Helena, MT 59620-0901.

Note:

For a table listing Region VIII's NSPS delegation status, see paragraph (c) of this section.

(29) State of Nebraska, Nebraska Department of Environmental Control, P.O. Box 94877, State House Station, Lincoln, NE 68509.

Lincoln-Lancaster County Health Department, Division of Environmental Health, 2200 St. Marys Avenue, Lincoln, NE 68502

(30) Nevada:

Nevada Division of Environmental Protection, 901 South Stewart Street, Suite 4001, Carson City, NV 89701-5249.

Clark County Division of Air Quality, 500 S Grand Central Parkway, 1st Floor, P.O. Box 555210, Las Vegas, NV 89155-5210.

Northern Nevada Public Health, Air Quality Management Division, 1001 E 9th Street, Building B, Reno, NV 89512.

Note 7 to paragraph (b)(30):

For tables listing the delegation status of agencies in Region IX, see paragraph (d) of this section.

(31) State of New Hampshire, New Hampshire Department of Environmental Services, Air Resources Division, 29 Hazen Drive, P.O. Box 95, Concord, NH 03302-0095.

(32) State of New Jersey: New Jersey Department of Environmental Protection, Division of Environmental Quality, Enforcement Element, John Fitch Plaza, CN-027, Trenton, NJ 08625.

(1) The following table lists the specific source and pollutant categories that have been delegated to the states in Region II. The (X) symbol is used to indicate each category that has been delegated.

	Subpart	State			
		New Jersey	New York	Puerto Rico	Virgin Islands
D	Fossil-Fuel Fired Steam Generators for Which Construction Commenced After August 17, 1971 (Steam Generators and Lignite Fired Steam Generators)	X	X	X	X
Da	Electric Utility Steam Generating Units for Which Construction Commenced After September 18, 1978	X		X	
Db	Industrial-Commercial-Institutional Steam Generating Units	X	X	X	X
E	Incinerators	X	X	X	X
F	Portland Cement Plants	X	X	X	X
G	Nitric Acid Plants	X	X	X	X
H	Sulfuric Acid Plants	X	X	X	X
I	Asphalt Concrete Plants	X	X	X	X
J	Petroleum Refineries—(All Categories)	X	X	X	X
K	Storage Vessels for Petroleum Liquids Constructed After June 11, 1973, and prior to May 19, 1978	X	X	X	X
Ka	Storage Vessels for Petroleum Liquids Constructed After May 18, 1978	X	X	X	
L	Secondary Lead Smelters	X	X	X	X
M	Secondary Brass and Bronze Ingot Production Plants	X	X	X	X
N	Iron and Steel Plants	X	X	X	X
O	Sewage Treatment Plants	X	X	X	X
P	Primary Copper Smelters	X	X	X	X
Q	Primary Zinc Smelters	X	X	X	X
R	Primary Lead Smelters	X	X	X	X
S	Primary Aluminum Reduction Plants	X	X	X	X
T	Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants	X	X	X	X
U	Phosphate Fertilizer Industry: Superphosphoric Acid Plants	X	X	X	X
V	Phosphate Fertilizer Industry: Diammonium Phosphate Plants	X	X	X	X
W	Phosphate Fertilizer Industry: Triple Superphosphate Plants	X	X	X	X
X	Phosphate Fertilizer Industry: Granular Triple Superphosphate	X	X	X	X

	Subpart	State			
		New Jersey	New York	Puerto Rico	Virgin Islands
Y	Coal Preparation Plants	X	X	X	X
Z	Ferroally Production Facilities	X	X	X	X
AA	Steel Plants: Electric Arc Furnaces	X	X	X	X
AAa	Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels in Steel Plants	X	X	X	
BB	Kraft Pulp Mills	X	X	X	
CC	Glass Manufacturing Plants	X	X	X	
DD	Grain Elevators	X	X	X	
EE	Surface Coating of Metal Furniture	X	X	X	
GG	Stationary Gas Turbines	X	X	X	
HH	Lime Plants	X	X	X	
KK	Lead Acid Battery Manufacturing Plants	X	X		
LL	Metallic Mineral Processing Plants	X	X	X	
MM	Automobile and Light-Duty Truck Surface Coating Operations	X	X		
NN	Phosphate Rock Plants	X	X		
PP	Ammonium Sulfate Manufacturing Plants	X	X		
QQ	Graphic Art Industry Publication Rotogravure Printing	X	X	X	X
RR	Pressure Sensitive Tape and Label Surface Coating Operations	X	X	X	
SS	Industrial Surface Coating: Large Appliances	X	X	X	
TT	Metal Coil Surface Coating	X	X	X	
UU	Asphalt Processing and Asphalt Roofing Manufacture	X	X	X	
VV	Equipment Leaks of Volatile Organic Compounds in Synthetic Organic Chemical Manufacturing Industry	X		X	
WW	Beverage Can Surface Coating Industry	X	X	X	
XX	Bulk Gasoline Terminals	X	X	X	
FFF	Flexible Vinyl and Urethane Coating and Printing	X	X	X	
GGG	Equipment Leaks of VOC in Petroleum Refineries	X		X	

	Subpart	State			
		New Jersey	New York	Puerto Rico	Virgin Islands
HHH	Synthetic Fiber Production Facilities	X		X	
JJJ	Petroleum Dry Cleaners	X	X	X	
KKK	Equipment Leaks of VOC from Onshore Natural Gas Processing Plants				
LLL	Onshore Natural Gas Processing Plants; SO ₂ Emissions		X		
OOO	Nonmetallic Mineral Processing Plants		X	X	
PPP	Wool Fiberglass Insulation Manufacturing Plants		X	X	

(33) State of New Mexico: New Mexico Environment Department, P.O. Box 5469, Santa Fe, New Mexico 87502-5469. Note: For a list of delegated standards for New Mexico (excluding Bernalillo County and Indian country), see paragraph (e)(1) of this section.

(34) New York: New York State Department of Environmental Conservation, 50 Wolf Road Albany, New York 12233, attention: Division of Air Resources.

(35) State of North Carolina: North Carolina Department of Environmental Quality, Division of Air Quality, 1641 Mail Service Center, Raleigh, North Carolina 27699-1641 or local agencies, Forsyth County Office of Environmental Assistance and Protection, 201 North Chestnut Street, Winston-Salem, North Carolina 27101-4120; Mecklenburg County Land Use and Environmental Services Agency, Air Quality, 2145 Suttle Avenue, Charlotte, North Carolina 28208; Western North Carolina Regional Air Quality Agency, 125 S. Lexington Ave., Suite 101, Asheville, North Carolina 28801-3661.

(36) State of North Dakota, North Dakota Department of Environmental Quality, 918 East Divide Avenue, Bismarck, ND 58501-1947.

Note:

For a table listing Region VIII's NSPS delegation status, see paragraph (c) of this section.

(37) State of Ohio:

(i) Medina, Summit and Portage Counties; Director, Akron Regional Air Quality Management District, 146 South High Street, Room 904, Akron, OH 44308.

(ii) Stark County; Director, Canton City Health Department, Air Pollution Control Division, 420 Market Avenue North, Canton, Ohio 44702-1544.

(iii) Butler, Clermont, Hamilton, and Warren Counties; Director, Hamilton County Department of Environmental Services, 250 William Howard Taft Road, Cincinnati, Ohio 45219-2660.

(iv) Cuyahoga County; Commissioner, Cleveland Department of Public Health, Division of Air Quality, 75 Erieview Plaza 2nd Floor, Cleveland, Ohio 44114.

(v) Clark, Darke, Greene, Miami, Montgomery, and Preble Counties; Director, Regional Air Pollution Control Agency, 117 South Main Street, Dayton, Ohio 45422-1280.

(vi) Lucas County and the City of Rossford (in Wood County); Director, City of Toledo, Division of Environmental Services, 348 South Erie Street, Toledo, OH 43604.

- (vii) Adams, Brown, Lawrence, and Scioto Counties; Portsmouth Local Air Agency, 605 Washington Street, Third Floor, Portsmouth, OH 45662.
- (viii) Allen, Ashland, Auglaize, Crawford, Defiance, Erie, Fulton, Hancock, Hardin, Henry, Huron, Marion, Mercer, Ottawa, Paulding, Putnam, Richland, Sandusky, Seneca, Van Wert Williams, Wood (Except City of Rossford), and Wyandot Counties; Ohio Environmental Protection Agency, Northwest District Office, Air Pollution Control, 347 North Dunbridge Road, Bowling Green, Ohio 43402.
- (ix) Ashtabula, Carroll, Columbiana, Holmes, Lorain, and Wayne Counties; Ohio Environmental Protection Agency, Northeast District Office, Air Pollution Unit, 2110 East Aurora Road, Twinsburg, OH 44087.
- (x) Athens, Belmont, Coshocton, Gallia, Guemsey, Harrison, Hocking, Jackson, Jefferson, Meigs, Monroe, Morgan, Muskingum, Noble, Perry, Pike, Ross, Tuscarawas, Vinton, and Washington Counties; Ohio Environmental Protection Agency, Southeast District Office, Air Pollution Unit, 2195 Front Street, Logan, OH 43138.
- (xi) Champaign, Clinton, Highland, Logan, and Shelby Counties; Ohio Environmental Protection Agency, Southwest District Office, Air Pollution Unit, 401 East Fifth Street, Dayton, Ohio 45402-2911.
- (xii) Delaware, Fairfield, Fayette, Franklin, Knox, Licking, Madison, Morrow, Pickaway, and Union Counties; Ohio Environmental Protection Agency, Central District Office, Air Pollution control, 50 West Town Street, Suite 700, Columbus, Ohio 43215.
- (xiii) Geauga and Lake Counties; Lake County General Health District, Air Pollution Control, 33 Mill Street, Painesville, OH 44077.
- (xiv) Mahoning and Trumbull Counties; Mahoning-Trumbull Air Pollution Control Agency, 345 Oak Hill Avenue, Suite 200, Youngstown, OH 44502.
- (38) State of Oklahoma, State of Oklahoma Department of Environmental Quality, Air Quality Division, P.O. Box 1677, Oklahoma City, OK 73101-1677.
- (39) State of Oregon.
 - (i) Oregon Department of Environmental Quality (ODEQ), 811 SW Sixth Avenue, Portland, OR 97204-1390, <http://www.deq.state.or.us>.
 - (ii) Lane Regional Air Pollution Authority (LRAPA), 1010 Main Street, Springfield, Oregon 97477, <http://www.lrapa.org>.
- (40)
 - (i) City of Philadelphia, Department of Public Health, Air Management Services, 321 University Avenue, Philadelphia, Pennsylvania 19104.
 - (ii) Commonwealth of Pennsylvania, Department of Environmental Protection, Bureau of Air Quality Control, P.O. Box 8468, 400 Market Street, Harrisburg, Pennsylvania 17105.
 - (iii) Allegheny County Health Department, Bureau of Environmental Quality, Division of Air Quality, 301 39th Street, Pittsburgh, Pennsylvania 15201.
- (41) State of Rhode Island, Rhode Island Department of Environmental Management, Office of Air Resources, 235 Promenade Street, Providence, RI 02908.
- (42) State of South Carolina: South Carolina Department of Health and Environmental Control, 2600 Bull Street, Columbia, South Carolina 29201.

(43) State of South Dakota, Air Quality Program, Department of Agriculture and Natural Resources, Joe Foss Building, 523 East Capitol, Pierre, SD 57501-3181.

(44) State of Tennessee: Tennessee Department of Environment and Conservation, Division of Air Pollution Control, William R. Snodgrass Tennessee Tower, 312 Rosa L. Parks Avenue, 15th Floor, Nashville, Tennessee 37243, or local agencies, Knox County Air Quality Management—Department of Public Health, 140 Dameron Avenue, Knoxville, Tennessee 37917; Metro Public Health Department, Pollution Control Division, 2500 Charlotte Ave., Nashville, Tennessee 37209; Chattanooga-Hamilton County Air Pollution Control Bureau, 6125 Preservation Drive, Chattanooga, Tennessee 37416; Shelby County Health Department, Pollution Control Section, 814 Jefferson Avenue, Memphis, Tennessee 38105.

(45) State of Texas, Texas Air Control Board, 6330 Highway 290 East, Austin, TX 78723.

(46) State of Utah, Division of Air Quality, Department of Environmental Quality, P.O. Box 144820, Salt Lake City, UT 84114-4820.

Note:

For a table listing Region VIII's NSPS delegation status, see paragraph (c) of this section.

(47) State of Vermont, Agency of Natural Resources, Department of Environmental Conservation, Air Quality and Climate Division, Davis 2, One National Life Drive, Montpelier, VT 05620-3802.

(48) Commonwealth of Virginia, Department of Environmental Quality, 629 East Main Street, Richmond, Virginia 23219.

(49) *State of Washington.*

(i) Washington State Department of Ecology (Ecology), P.O. Box 47600, Olympia, WA 98504-7600, <http://www.ecy.wa.gov/>

(ii) Benton Clean Air Authority (BCAA), 650 George Washington Way, Richland, WA 99352-4289, <http://www.bcaa.net/>

(iii) Northwest Air Pollution Control Authority (NWAPA), 1600 South Second St., Mount Vernon, WA 98273-5202, <http://www.nwair.org/>

(iv) Olympic Regional Clean Air Agency (ORCAA), 909 Sleater-Kinney Road S.E., Suite 1, Lacey, WA 98503-1128, <http://www.orcaa.org/>

(v) Puget Sound Clean Air Agency (PSCAA), 110 Union Street, Suite 500, Seattle, WA 98101-2038, <http://www.pscleanair.org/>

(vi) Spokane County Air Pollution Control Authority (SCAPCA), West 1101 College, Suite 403, Spokane, WA 99201, <http://www.scapca.org/>

(vii) Southwest Clean Air Agency (SWCAA), 1308 NE. 134th St., Vancouver, WA 98685-2747, <http://www.swcleanair.org/>

(viii) Yakima Regional Clean Air Authority (YRCAA), 6 South 2nd Street, Suite 1016, Yakima, WA 98901, <http://co.yakima.wa.us/cleanair/default.htm>

(ix) The following table lists the delegation status of the New Source Performance Standards for the State of Washington. An "X" indicates the subpart has been delegated, subject to all the conditions and limitations set forth in Federal law and the letters granting delegation. Some authorities cannot be delegated and are retained by EPA. Refer to the letters granting delegation for a discussion of these retained authorities. The dates noted at the end of the table indicate the effective dates of Federal rules

that have been delegated. Authority for implementing and enforcing any amendments made to these rules after these effective dates are not delegated.

NSPS Subparts Delegated to Washington Air Agencies

Subpart ¹	Washington							
	Ecology ²	BCAA ³	NWAPA ⁴	ORCAA ⁵	PSCAA ⁶	SCAPCA ⁷	SWCAA ⁸	YRCAA ⁹
A General Provisions	X	X	X	X	X	X	X	X
B Adoption and Submittal of State Plans for Designated Facilities								
C Emission Guidelines and Compliance Times								
Cb Large Municipal Waste Combustors that are Constructed on or before September 20, 1994 (Emission Guidelines and Compliance Times)								
Cc Municipal Solid Waste Landfills (Emission Guidelines and Compliance Times)								
Cd Sulfuric Acid Production Units (Emission Guidelines and Compliance Times)								
Ce Hospital/Medical/Infectious Waste Incinerators (Emission Guidelines and Compliance Times)								
D Fossil-Fuel-Fired Steam Generators for which Construction is Commenced after August 17, 1971	X	X	X	X	X	X	X	X
Da Electric Utility Steam Generating Units for which Construction is Commenced after September 18, 1978	X	X	X	X	X	X	X	X
Db Industrial-Commercial-Institutional Steam Generating Units	X	X	X	X	X	X	X	X
Dc Small Industrial-Commercial-Institutional Steam Generating Units	X	X	X	X	X	X	X	X
E Incinerators	X	X	X	X	X	X	X	X
Ea Municipal Waste Combustors for which Construction is Commenced after December 20, 1989 and on or before September 20, 1994	X	X	X	X	X	X	X	X
Eb—Large Municipal Waste Combustors		X		X	X	X		
Ec—Hospital/Medical/Infectious Waste	X	X	X	X	X	X		

NSPS Subparts Delegated to Washington Air Agencies

Subpart ¹	Washington							
	Ecology ²	BCAA ³	NWAPA ⁴	ORCAA ⁵	PSCAA ⁶	SCAPCA ⁷	SWCAA ⁸	YRCAA ⁹
Incinerators								
F Portland Cement Plants	X	X	X	X	X	X	X	X
G Nitric Acid Plants	X	X	X	X	X	X	X	X
H Sulfuric Acid Plants	X	X	X	X	X	X	X	X
I Hot Mix Asphalt Facilities	X	X	X	X	X	X	X	X
J Petroleum Refineries	X	X	X	X	X	X	X	X
K Storage Vessels for Petroleum Liquids for which Construction, Reconstruction, or Modification Commenced after June 11, 1973 and prior to May 19, 1978	X	X	X	X	X	X	X	X
Ka Storage Vessels for Petroleum Liquids for which Construction, Reconstruction, or Modification Commenced after May 18, 1978 and prior to July 23, 1984	X	X	X	X	X	X	X	X
Kb VOC Liquid Storage Vessels (including Petroleum Liquid Storage Vessels) for which Construction, Reconstruction, or Modification Commenced after July 23, 1984	X	X	X	X	X	X	X	X
L Secondary Lead Smelters	X	X	X	X	X	X	X	X
M Secondary Brass and Bronze Production Plants	X	X	X	X	X	X	X	X
N Primary Emissions from Basic Oxygen Process Furnaces for which Construction is Commenced after June 11, 1973	X	X	X	X	X	X	X	X
Na Secondary Emissions from Basic Oxygen Process Steel-making Facilities for which Construction is Commenced after January 20, 1983	X	X	X	X	X	X	X	X
O Sewage Treatment Plants	X	X	X	X	X	X	X	X
P Primary Copper Smelters	X	X	X	X	X	X	X	X
Q Primary Zinc Smelters	X	X	X	X	X	X	X	X
R Primary Lead Smelters	X	X	X	X	X	X	X	X

NSPS Subparts Delegated to Washington Air Agencies

Subpart¹	Washington							
	Ecology²	BCAA³	NWAPA⁴	ORCAA⁵	PSCAA⁶	SCAPCA⁷	SWCAA⁸	YRCAA⁹
S Primary Aluminum Reduction Plants ¹⁰	X							
T Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants	X	X	X	X	X	X	X	X
U Phosphate Fertilizer Industry: Superphosphoric Acid Plants	X	X	X	X	X	X	X	X
V Phosphate Fertilizer Industry: Diammonium Phosphate Plants	X	X	X	X	X	X	X	X
W Phosphate Fertilizer Industry: Triple Superphosphate Plants	X	X	X	X	X	X	X	X
X Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities	X	X	X	X	X	X	X	X
Y Coal Preparation Plants	X	X	X	X	X	X	X	X
Z Ferroalloy Production Facilities	X	X	X	X	X	X	X	X
AA Steel Plants: Electric Arc Furnaces Constructed after October 21, 1974 and on or before August 17, 1983	X	X	X	X	X	X	X	X
AAa Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed after August 7, 1983	X	X	X	X	X	X	X	X
BB Kraft Pulp Mills ¹¹	X							
CC Glass Manufacturing Plants	X	X	X	X	X	X	X	X
DD Grain Elevators	X	X	X	X	X	X	X	X
EE Surface Coating of Metal Furniture	X	X	X	X	X	X	X	X
GG Stationary Gas Turbines	X	X	X	X	X	X	X	X
HH Lime Manufacturing Plants	X	X	X	X	X	X	X	X
KK Lead-Acid Battery Manufacturing Plants	X	X	X	X	X	X	X	X
LL Metallic Mineral Processing Plants	X	X	X	X	X	X	X	X
MM Automobile and Light Duty Truck Surface Coating Operations	X	X	X	X	X	X	X	X

NSPS Subparts Delegated to Washington Air Agencies

Subpart ¹	Washington							
	Ecology ²	BCAA ³	NWAPA ⁴	ORCAA ⁵	PSCAA ⁶	SCAPCA ⁷	SWCAA ⁸	YRCAA ⁹
NN Phosphate Rock Plants	X	X	X	X	X	X	X	X
PP Ammonium Sulfate Manufacture	X	X	X	X	X	X	X	X
QQ Graphic Arts Industry: Publication Rotogravure Printing	X	X	X	X	X	X	X	X
RR Pressure Sensitive Tape and Label Surface Coating Standards	X	X	X	X	X	X	X	X
SS Industrial Surface Coating: Large Appliances	X	X	X	X	X	X	X	X
TT Metal Coil Surface Coating	X	X	X	X	X	X	X	X
UU Asphalt Processing and Asphalt Roof Manufacture	X	X	X	X	X	X	X	X
VV Equipment Leaks of VOC in Synthetic Organic Chemical Manufacturing Industry	X	X	X	X	X	X	X	X
WW Beverage Can Surface Coating Industry	X	X	X	X	X	X	X	X
XX Bulk Gasoline Terminals	X	X	X	X	X	X	X	X
AAA New Residential Wood Heaters								
BBB Rubber Tire Manufacturing Industry	X	X	X	X	X	X	X	X
DDD VOC Emissions from Polymer Manufacturing Industry	X	X	X	X	X	X	X	X
FFF Flexible Vinyl and Urethane Coating and Printing	X	X	X	X	X	X	X	X
GGG Equipment Leaks of VOC in Petroleum Refineries	X	X	X	X	X	X	X	X
HHH Synthetic Fiber Production Facilities	X	X	X	X	X	X	X	X
III VOC Emissions from Synthetic Organic Chemical Manufacturing Industry Air Oxidation Unit Processes	X	X	X	X	X	X	X	X
JJJ Petroleum Dry Cleaners	X	X	X	X	X	X	X	X
KKK Equipment Leaks of VOC from Onshore Natural Gas Processing Plants	X	X	X	X	X	X	X	X

NSPS Subparts Delegated to Washington Air Agencies

Subpart¹	Washington							
	Ecology²	BCAA³	NWAPA⁴	ORCAA⁵	PSCAA⁶	SCAPCA⁷	SWCAA⁸	YRCAA⁹
LLL Onshore Natural Gas Processing: SO ₂ Emissions	X	X	X	X	X	X	X	X
NNN VOC Emissions from Synthetic Organic Chemical Manufacturing Industry Distillation Operations	X	X	X	X	X	X	X	X
OOO Nonmetallic Mineral Processing Plants			X		X		X	
PPP Wool Fiberglass Insulation Manufacturing Plants	X	X	X	X	X	X	X	X
QQQ VOC Emissions from Petroleum Refinery Wastewater Systems	X	X	X	X	X	X	X	X
RRR VOCs from Synthetic Organic Chemical Manufacturing Industry Reactor Processes	X	X	X	X	X	X	X	X
SSS Magnetic Tape Coating Facilities	X	X	X	X	X	X	X	X
TTT Industrial Surface Coating: Surface Coating of Plastic Parts for Business Machines	X	X	X	X	X	X	X	X
UUU Calciners and Dryers in Mineral Industries	X	X	X	X	X	X	X	X
VVV Polymeric Coating of Supporting Substrates Facilities	X	X	X	X	X	X	X	X
WWW Municipal Solid Waste Landfills	X	X	X	X	X	X	X	X
AAAA Small Municipal Waste Combustion Units for which Construction is Commenced after August 30, 1999 or for which Modification or Reconstruction is Commenced after June 6, 2001	X	X		X	X	X		X
BBBB Small Municipal Waste Combustion Units Constructed on or before August 30, 1999 (Emission Guidelines and Compliance Times)								
CCCC Commercial and Industrial Solid Waste Incineration Units for which Construction is Commenced after November, 30, 1999 or for which Modification or Reconstruction is Commenced on or after June 1, 2001	X	X		X	X	X		X
DDDD Commercial and Industrial Solid Waste Incineration Units that Commenced Construction								

NSPS Subparts Delegated to Washington Air Agencies

Subpart ¹	Washington							
	Ecology ²	BCAA ³	NWAPA ⁴	ORCAA ⁵	PSCAA ⁶	SCAPCA ⁷	SWCAA ⁸	YRCAA ⁹
on or before November 30, 1999 (Emission Guidelines and Compliance Times)								

¹ Any authority within any subpart of this part that is not delegable, is not delegated. Please refer to Attachment B to the delegation letters for a listing of the NSPS authorities excluded from delegation.

² Washington State Department of Ecology, for 40 CFR 60.17(h)(1), (h)(2), (h)(3) and 40 CFR part 60, subpart AAAA, as in effect on June 6, 2001; for 40 CFR part 60, subpart CCCC, as in effect on June 1, 2001; and for all other NSPS delegated, as in effect February 20, 2001.

³ Benton Clean Air Authority, for 40 CFR 60.17(h)(1), (h)(2), (h)(3) and 40 CFR part 60, subpart AAAA, as in effect on June 6, 2001; for 40 CFR part 60, subpart CCCC, as in effect on June 1, 2001; and for all other NSPS delegated, as in effect February 20, 2001.

⁴ Northwest Air Pollution Authority, for all NSPS delegated, as in effect on July 1, 2000.

⁵ Olympic Regional Clean Air Authority, for 40 CFR 60.17(h)(1), (h)(2), (h)(3) and 40 CFR part 60, subpart AAAA, as in effect on June 6, 2001; for 40 CFR part 60, subpart CCCC, as in effect on June 1, 2001; and for all other NSPS delegated, as in effect February 20, 2001.

⁶ Puget Sound Clean Air Authority, for all NSPS delegated, as in effect on July 1, 2002.

⁷ Spokane County Air Pollution Control Authority, for 40 CFR 60.17(h)(1), (h)(2), (h)(3) and 40 CFR part 60, subpart AAAA, as in effect on June 6, 2001; for 40 CFR part 60, subpart CCCC, as in effect on June 1, 2001; and for all other NSPS delegated, as in effect February 20, 2001.

⁸ Southwest Clean Air Agency, for all NSPS delegated, as in effect on July 1, 2000.

⁹ Yakima Regional Clean Air Authority, for 40 CFR 60.17(h)(1), (h)(2), (h)(3) and 40 CFR part 60, subpart AAAA, as in effect on June 6, 2001; for 40 CFR part 60, subpart CCCC, as in effect on June 1, 2001; and for all other NSPS delegated, as in effect February 20, 2001.

¹⁰ Subpart S of this part is not delegated to local agencies in Washington because the Washington State Department of Ecology retains sole authority to regulate Primary Aluminum Plants, pursuant to Washington Administrative Code 173-415-010.

¹¹ Subpart BB of this part is not delegated to local agencies in Washington because the Washington State Department of Ecology retains sole authority to regulate Kraft and Sulfite Pulp Mill, pursuant to Washington State Administrative Code 173-405-012 and 173-410-012.

(50) State of West Virginia, Department of Environmental Protection, Division of Air Quality, 601 57th Street, SE., Charleston, West Virginia 25304.

(51) State of Wisconsin: Wisconsin Department of Natural Resources, 101 South Webster St., P.O. Box 7921, Madison, Wisconsin 53707-7921.

(52) State of Wyoming, Department of Environmental Quality, Air Quality Division, Herschler Building, 122 West 25th Street, Cheyenne, WY 82002.

Note:

For a table listing Region VIII's NSPS delegation status, see paragraph (c) of this section.

(53) Territory of Guam: Guam Environmental Protection Agency, P.O. Box 22439 GMF, Barrigada, Guam 96921.

Note:

For tables listing the delegation status of agencies in Region IX, see paragraph (d) of this section.

(54) Commonwealth of Puerto Rico: Commonwealth of Puerto Rico Environmental Quality Board, P.O. Box 11488, Santurce, PR 00910, Attention: Air Quality Area Director (see table under § 60.4(b)(FF)(1)).

(55) U.S. Virgin Islands: U.S. Virgin Islands Department of Conservation and Cultural Affairs, P.O. Box 578, Charlotte Amalie, St. Thomas, VI 00801.

(56) American Samoa: American Samoa Environmental Protection Agency, P.O. Box PPA, Pago Pago, American Samoa 96799.

Note:

For tables listing the delegation status of agencies in Region IX, see paragraph (d) of this section.

(57) Commonwealth of the Northern Mariana Islands: CNMI Division of Environmental Quality, P.O. Box 501304, Saipan, MP 96950.

Note:

For tables listing the delegation status of agencies in Region IX, see paragraph (d) of this section.

(c) The delegation status table for New Source Performance Standards for Region VIII can be found online at <http://www2.epa.gov/region8/air-program>.

(d) The following tables list the specific part 60 standards that have been delegated unchanged to the air pollution control agencies in Region IX. The (X) symbol is used to indicate each standard that has been delegated. The following provisions of this subpart are not delegated: §§ 60.4(b), 60.8(b), 60.9, 60.11(b), 60.11(e), 60.13(a), 60.13(d)(2), 60.13(g), 60.13(i).

(1) *Arizona*. The following table identifies delegations for Arizona:

Table 3 to Paragraph (d)(1)—Delegation Status for New Source Performance Standards for Arizona					
	Subpart	Air pollution control agency			
		Arizona DEQ	Maricopa County	Pima County	Pinal County
A	General Provisions	X	X	X	X
D	Fossil-Fuel Fired Steam Generators Constructed After August 17, 1971	X	X	X	X
Da	Electric Utility Steam Generating Units Constructed After September 18, 1978	X	X	X	X
Db	Industrial-Commercial-Institutional Steam Generating Units	X	X	X	X

Table 3 to Paragraph (d)(1)—Delegation Status for New Source Performance Standards for Arizona

	Subpart	Air pollution control agency			
		Arizona DEQ	Maricopa County	Pima County	Pinal County
Dc	Small Industrial-Commercial-Institutional Steam Generating Units	X	X	X	X
E	Incinerators	X	X	X	X
Ea	Municipal Waste Combustors Constructed After December 20, 1989 and On or Before September 20, 1994	X	X	X	X
Eb	Large Municipal Waste Combustors Constructed After September 20, 1994	X	X	X	
Ec	Hospital/Medical/Infectious Waste Incinerators for Which Construction is Commenced After June 20, 1996	X	X	X	
F	Portland Cement Plants	X		X	X
G	Nitric Acid Plants	X	X	X	X
Ga	Nitric Acid Plants For Which Construction, Reconstruction or Modification Commenced After October 14, 2011		X	X	
H	Sulfuric Acid Plant	X	X	X	X
I	Hot Mix Asphalt Facilities	X	X	X	X
J	Petroleum Refineries	X		X	X
Ja	Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007			X	
K	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978	X	X	X	X
Ka	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984	X	X	X	X
Kb	Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984	X	X	X	X
L	Secondary Lead Smelters	X		X	X
M	Secondary Brass and Bronze Production Plants	X	X	X	X
N	Primary Emissions from Basic Oxygen Process Furnaces for Which Construction is Commenced After June 11, 1973	X	X	X	X

Table 3 to Paragraph (d)(1)—Delegation Status for New Source Performance Standards for Arizona

	Subpart	Air pollution control agency			
		Arizona DEQ	Maricopa County	Pima County	Pinal County
Na	Secondary Emissions from Basic Oxygen Process Steelmaking Facilities for Which Construction is Commenced After January 20, 1983	X	X	X	X
O	Sewage Treatment Plants	X	X	X	X
P	Primary Copper Smelters	X		X	X
Q	Primary Zinc Smelters	X		X	X
R	Primary Lead Smelters	X		X	X
S	Primary Aluminum Reduction Plants	X	X	X	X
T	Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants	X	X	X	X
U	Phosphate Fertilizer Industry: Superphosphoric Acid Plants	X	X	X	X
V	Phosphate Fertilizer Industry: Diammonium Phosphate Plants	X	X	X	X
W	Phosphate Fertilizer Industry: Triple Superphosphate Plants	X	X	X	X
X	Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities	X	X	X	X
Y	Coal Preparation and Processing Plants	X	X	X	X
Z	Ferroalloy Production Facilities	X	X	X	X
AA	Steel Plants: Electric Arc Furnaces Constructed After October 21, 1974 and On or Before August 17, 1983	X	X	X	X
AAa	Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After August 7, 1983	X	X	X	X
BB	Kraft Pulp Mills	X	X	X	X
BBa	Kraft Pulp Mill Sources for which Construction, Reconstruction or Modification Commenced after May 23, 2013		X	X	
CC	Glass Manufacturing Plants	X	X	X	X
DD	Grain Elevators	X	X	X	X
EE	Surface Coating of Metal Furniture	X	X	X	X
FF	(Reserved)				

Table 3 to Paragraph (d)(1)—Delegation Status for New Source Performance Standards for Arizona

	Subpart	Air pollution control agency			
		Arizona DEQ	Maricopa County	Pima County	Pinal County
GG	Stationary Gas Turbines	X	X	X	X
HH	Lime Manufacturing Plants	X	X	X	X
KK	Lead-Acid Battery Manufacturing Plants	X	X	X	X
LL	Metallic Mineral Processing Plants	X	X	X	X
MM	Automobile and Light Duty Trucks Surface Coating Operations	X	X	X	X
NN	Phosphate Rock Plants	X	X	X	X
PP	Ammonium Sulfate Manufacture	X	X	X	X
QQ	Graphic Arts Industry: Publication Rotogravure Printing	X	X	X	X
RR	Pressure Sensitive Tape and Label Surface Coating Operations	X	X	X	X
SS	Industrial Surface Coating: Large Appliances	X	X	X	X
TT	Metal Coil Surface Coating	X	X	X	X
UU	Asphalt Processing and Asphalt Roofing Manufacture	X	X	X	X
VV	Equipment Leaks of VOC in the Synthetic Organic Industry Chemicals Manufacturing	X	X	X	X
VVa	Equipment Leaks of VOC in the Synthetic Organic Industry for Which Construction, Reconstruction, or Chemicals Manufacturing Modification Commenced After November 7, 2006	X	X	X	
WW	Beverage Can Surface Coating Industry	X	X	X	X
XX	Bulk Gasoline Terminals	X	X	X	X
AAA	New Residential Wood Heaters	X	X	X	X
BBB	Rubber Tire Manufacturing Industry	X	X	X	X
CCC	(Reserved)				
DDD	Volatile Organic Compounds (VOC) Emissions from the Polymer Manufacturing Industry	X	X	X	X
EEE	(Reserved)				
FFF	Flexible Vinyl and Urethane Coating and Printing	X	X	X	X

Table 3 to Paragraph (d)(1)—Delegation Status for New Source Performance Standards for Arizona

	Subpart	Air pollution control agency			
		Arizona DEQ	Maricopa County	Pima County	Pinal County
GGG	Equipment Leaks of VOC in Petroleum Refineries	X		X	X
GGGa	Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006	X		X	
HHH	Synthetic Fiber Production Facilities	X	X	X	X
III	Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes	X	X	X	X
JJJ	Petroleum Dry Cleaners	X	X	X	X
KKK	Equipment Leaks of VOC From Onshore Natural Gas Processing Plants	X	X	X	X
LLL	Onshore Natural Gas Processing: SO ₂ Emissions	X	X	X	X
MMM	(Reserved)				
NNN	Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations	X	X	X	X
OOO	Nonmetallic Mineral Processing Plants	X	X	X	X
PPP	Wool Fiberglass Insulation Manufacturing Plants	X	X	X	X
QQQ	VOC Emissions From Petroleum Refinery Wastewater Systems	X		X	X
RRR	Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes	X	X	X	
SSS	Magnetic Tape Coating Facilities	X	X	X	X
TTT	Industrial Surface Coating: Surface Coating of Plastic Parts for Business Machines	X	X	X	X
UUU	Calciners and Dryers in Mineral Industries	X	X	X	
VVV	Polymeric Coating of Supporting Substrates Facilities	X	X	X	X
WWW	Municipal Solid Waste Landfills	X	X	X	
XXX	Municipal Solid Waste Landfills that Commenced Construction, Reconstruction, or Modification After July 17, 2014		X	X	
AAAA	Small Municipal Waste Combustion Units for Which Construction is Commenced After August 30, 1999 or for Which Modification or Reconstruction is Commenced After June 6, 2001	X	X	X	

Table 3 to Paragraph (d)(1)—Delegation Status for New Source Performance Standards for Arizona

	Subpart	Air pollution control agency			
		Arizona DEQ	Maricopa County	Pima County	Pinal County
CCCC	Commercial and Industrial Solid Waste Incineration Units for Which Construction Is Commenced After November 30, 1999 or for Which Modification or Reconstruction Is Commenced on or After June 1, 2001	X	X	X	
EEEE	Other Solid Waste Incineration Units for Which Construction is Commenced After December 9, 2004, or for Which Modification or Reconstruction is Commenced on or After June 16, 2006	X	X	X	
GGGG	(Reserved)				
HHHH	(Reserved)				
IIII	Stationary Compression Ignition Internal Combustion Engines	X	X	X	
JJJJ	Stationary Spark Ignition Internal Combustion Engines		X	X	
KKKK	Stationary Combustion Turbines	X	X	X	
LLLL	New Sewage Sludge Incineration Units			X	
MMMM	Emissions Guidelines and Compliance Times for Existing Sewage Sludge Incineration Units	X			
OOOO	Crude Oil and Natural Gas Production, Transmission, and Distribution		X	X	
OOOOa	Standards of Performance for Crude Oil and Natural Gas Facilities for Which Construction, Modification or Reconstruction Commenced After September 18, 2015		X	X	
QQQQ	Standards of Performance for New Residential Hydronic Heaters and Forced-Air Furnaces		X	X	
TTTT	Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units		X	X	

(2) *California*. The following tables identify delegations for each of the local air pollution control agencies of California.

(i) Delegations for Amador County Air Pollution Control District, Antelope Valley Air Quality Management District, Bay Area Air Quality Management District, and Butte County Air Quality Management District are shown in the following table:

Table 4 to Paragraph (d)(2)(i)—Delegation Status for New Source Performance Standards for Amador County APCD, Antelope Valley AQMD, Bay Area AQMD, and Butte County AQMD

	Subpart	Air pollution control agency

Permit Issued: [month day, year]

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		Amador County APCD	Antelope Valley AQMD	Bay Area AQMD	Butte County AQMD
A	General Provisions		X		
Ba	Adoption and Submittal of State Plans for Designated Facilities		X		
Cf	Emission Guidelines and Compliance Times for Municipal Solid Waste Landfills		X		
D	Fossil-Fuel Fired Steam Generators Constructed After August 17, 1971		X	X	
Da	Electric Utility Steam Generating Units Constructed After September 18, 1978		X	X	
Db	Industrial-Commercial-Institutional Steam Generating Units		X	X	
Dc	Small Industrial-Commercial-Institutional Steam Generating Units		X	X	
E	Incinerators		X	X	
Ea	Municipal Waste Combustors Constructed After December 20, 1989 and On or Before September 20, 1994		X	X	
Eb	Large Municipal Waste Combustors Constructed After September 20, 1994		X		
Ec	Hospital/Medical/Infectious Waste Incinerators for Which Construction is Commenced After June 20, 1996		X		
F	Portland Cement Plants		X	X	
G	Nitric Acid Plants		X	X	
Ga	Nitric Acid Plants For Which Construction, Reconstruction or Modification Commenced After October 14, 2011		X		
H	Sulfuric Acid Plant		X	X	
I	Hot Mix Asphalt Facilities		X	X	
J	Petroleum Refineries		X	X	
Ja	Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007		X		
K	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978		X	X	
Ka	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984		X	X	

Table 4 to Paragraph (d)(2)(i)—Delegation Status for New Source Performance Standards for Amador County APCD, Antelope Valley AQMD, Bay Area AQMD, and Butte County AQMD

	Subpart	Air pollution control agency			
		Amador County APCD	Antelope Valley AQMD	Bay Area AQMD	Butte County AQMD
Kb	Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984		X	X	
L	Secondary Lead Smelters		X	X	
M	Secondary Brass and Bronze Production Plants		X	X	
N	Primary Emissions from Basic Oxygen Process Furnaces for Which Construction is Commenced After June 11, 1973		X	X	
Na	Secondary Emissions from Basic Oxygen Process Steelmaking Facilities for Which Construction is Commenced After January 20, 1983		X	X	
O	Sewage Treatment Plants		X	X	
P	Primary Copper Smelters		X	X	
Q	Primary Zinc Smelters		X	X	
R	Primary Lead Smelters		X	X	
S	Primary Aluminum Reduction Plants		X	X	
T	Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants		X		
U	Phosphate Fertilizer Industry: Superphosphoric Acid Plants		X	X	
V	Phosphate Fertilizer Industry: Diammonium Phosphate Plants		X	X	
W	Phosphate Fertilizer Industry: Triple Superphosphate Plants		X	X	
X	Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities		X	X	
Y	Coal Preparation and Processing Plants		X	X	
Z	Ferroalloy Production Facilities		X	X	
AA	Steel Plants: Electric Arc Furnaces Constructed After October 21, 1974 and On or Before August 17, 1983		X	X	
AAa	Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After August 7, 1983		X	X	

Table 4 to Paragraph (d)(2)(i)—Delegation Status for New Source Performance Standards for Amador County APCD, Antelope Valley AQMD, Bay Area AQMD, and Butte County AQMD

	Subpart	Air pollution control agency			
		Amador County APCD	Antelope Valley AQMD	Bay Area AQMD	Butte County AQMD
BB	Kraft Pulp Mills		X	X	
BBa	Kraft Pulp Mill Sources for which Construction, Reconstruction or Modification Commenced after May 23, 2013		X		
CC	Glass Manufacturing Plants		X	X	
DD	Grain Elevators		X	X	
EE	Surface Coating of Metal Furniture		X	X	
FF	(Reserved)				
GG	Stationary Gas Turbines		X	X	
HH	Lime Manufacturing Plants		X	X	
KK	Lead-Acid Battery Manufacturing Plants		X	X	
LL	Metallic Mineral Processing Plants		X	X	
MM	Automobile and Light Duty Trucks Surface Coating Operations		X	X	
NN	Phosphate Rock Plants		X	X	
PP	Ammonium Sulfate Manufacture		X	X	
QQ	Graphic Arts Industry: Publication Rotogravure Printing		X	X	
RR	Pressure Sensitive Tape and Label Surface Coating Operations		X	X	
SS	Industrial Surface Coating: Large Appliances		X	X	
TT	Metal Coil Surface Coating		X	X	
UU	Asphalt Processing and Asphalt Roofing Manufacture		X	X	
VV	Equipment Leaks of VOC in the Synthetic Organic Industry Chemicals Manufacturing		X	X	
VVa	Equipment Leaks of VOC in the Synthetic Organic Industry for Which Construction, Reconstruction, or Chemicals Manufacturing Modification Commenced After November 7, 2006		X		
WW	Beverage Can Surface Coating Industry		X	X	

Table 4 to Paragraph (d)(2)(i)—Delegation Status for New Source Performance Standards for Amador County APCD, Antelope Valley AQMD, Bay Area AQMD, and Butte County AQMD

	Subpart	Air pollution control agency			
		Amador County APCD	Antelope Valley AQMD	Bay Area AQMD	Butte County AQMD
XX	Bulk Gasoline Terminals				
AAA	New Residential Wood Heaters		X	X	
BBB	Rubber Tire Manufacturing Industry		X	X	
CCC	(Reserved)				
DDD	Volatile Organic Compounds (VOC) Emissions from the Polymer Manufacturing Industry		X	X	
EEE	(Reserved)				
FFF	Flexible Vinyl and Urethane Coating and Printing		X	X	
GGG	Equipment Leaks of VOC in Petroleum Refineries		X	X	
GGGa	Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006		X		
HHH	Synthetic Fiber Production Facilities		X	X	
III	Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes		X		
JJJ	Petroleum Dry Cleaners		X	X	
KKK	Equipment Leaks of VOC From Onshore Natural Gas Processing Plants		X	X	
LLL	Onshore Natural Gas Processing: SO ₂ Emissions		X		
MMM	(Reserved)				
NNN	Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations		X	X	
OOO	Nonmetallic Mineral Processing Plants		X	X	
PPP	Wool Fiberglass Insulation Manufacturing Plants		X	X	
QQQ	VOC Emissions From Petroleum Refinery Wastewater Systems		X		
RRR	Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes		X		

Table 4 to Paragraph (d)(2)(i)—Delegation Status for New Source Performance Standards for Amador County APCD, Antelope Valley AQMD, Bay Area AQMD, and Butte County AQMD

	Subpart	Air pollution control agency			
		Amador County APCD	Antelope Valley AQMD	Bay Area AQMD	Butte County AQMD
SSS	Magnetic Tape Coating Facilities		X	X	
TTT	Industrial Surface Coating: Surface Coating of Plastic Parts for Business Machines		X	X	
UUU	Calciners and Dryers in Mineral Industries		X	X	
VVV	Polymeric Coating of Supporting Substrates Facilities		X	X	
WWW	Municipal Solid Waste Landfills		X		
XXX	Municipal Solid Waste Landfills that Commenced Construction, Reconstruction, or Modification After July 17, 2014		X		
AAAA	Small Municipal Waste Combustion Units for Which Construction is Commenced After August 30, 1999 or for Which Modification or Reconstruction is Commenced After June 6, 2001		X		
CCCC	Commercial and Industrial Solid Waste Incineration Units for Which Construction Is Commenced After November 30, 1999 or for Which Modification or Reconstruction Is Commenced on or After June 1, 2001		X		
DDDD	Emissions Guidelines and Compliance Times for Commercial and Industrial Solid Waste Incineration Units		X		
EEEE	Other Solid Waste Incineration Units for Which Construction is Commenced After December 9, 2004, or for Which Modification or Reconstruction is Commenced on or After June 16, 2006		X		
GGGG	(Reserved)				
HHHH	(Reserved)				
IIII	Stationary Compression Ignition Internal Combustion Engines		X		
JJJJ	Stationary Spark Ignition Internal Combustion Engines		X		
KKKK	Stationary Combustion Turbines		X		
LLLL	New Sewage Sludge Incineration Units		X		
MMMM	Emissions Guidelines and Compliance Times for Existing Sewage Sludge Incineration Units		X		

Table 4 to Paragraph (d)(2)(i)—Delegation Status for New Source Performance Standards for Amador County APCD, Antelope Valley AQMD, Bay Area AQMD, and Butte County AQMD

	Subpart	Air pollution control agency			
		Amador County APCD	Antelope Valley AQMD	Bay Area AQMD	Butte County AQMD
OOOO	Crude Oil and Natural Gas Production, Transmission, and Distribution		X		
OOOOa	Standards of Performance for Crude Oil and Natural Gas Facilities for Which Construction, Modification or Reconstruction Commenced After September 18, 2015		X		
TTTT	Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units		X		
UUUUa	Emission Guidelines for Greenhouse Gas Emissions From Existing Electric Utility Generating Units		X		

(ii) [Reserved]

(iii) Delegations for Glenn County Air Pollution Control District, Great Basin Unified Air Pollution Control District, Imperial County Air Pollution Control District, and Kern County Air Pollution Control District are shown in the following table:

Delegation Status for New Source Performance Standards for Glenn County APCD, Great Basin Unified APCD, Imperial County APCD, and Kern County APCD

	Subpart	Air pollution control agency			
		Glenn County APCD	Great Basin Unified APCD	Imperial County APCD	Kern County APCD
A	General Provisions		X		X
D	Fossil-Fuel Fired Steam Generators Constructed After August 17, 1971		X		X
Da	Electric Utility Steam Generating Units Constructed After September 18, 1978		X		X
Db	Industrial-Commercial-Institutional Steam Generating Units		X		X
Dc	Small Industrial Steam Generating Units		X		X
E	Incinerators		X		X
Ea	Municipal Waste Combustors Constructed After December 20, 1989 and On or Before September 20, 1994		X		

Delegation Status for New Source Performance Standards for Glenn County APCD, Great Basin Unified APCD, Imperial County APCD, and Kern County APCD

	Subpart	Air pollution control agency			
		Glenn County APCD	Great Basin Unified APCD	Imperial County APCD	Kern County APCD
Eb	Municipal Waste Combustors Constructed After September 20, 1994				
Ec	Hospital/Medical/Infectious Waste Incinerators for Which Construction is Commenced After June 20, 1996				
F	Portland Cement Plants		X		X
G	Nitric Acid Plants		X		X
H	Sulfuric Acid Plants		X		
I	Hot Mix Asphalt Facilities		X		X
J	Petroleum Refineries		X		X
K	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978		X		X
Ka	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984		X		X
Kb	Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984		X		X
L	Secondary Lead Smelters		X		X
M	Secondary Brass and Bronze Production Plants		X		X
N	Primary Emissions from Basic Oxygen Process Furnaces for Which Construction is Commenced After June 11, 1973		X		X
Na	Secondary Emissions from Basic Oxygen Process Steelmaking Facilities for Which Construction is Commenced After January 20, 1983		X		X
O	Sewage Treatment Plants		X		X
P	Primary Copper Smelters		X		X
Q	Primary Zinc Smelters		X		X

Delegation Status for New Source Performance Standards for Glenn County APCD, Great Basin Unified APCD, Imperial County APCD, and Kern County APCD

	Subpart	Air pollution control agency			
		Glenn County APCD	Great Basin Unified APCD	Imperial County APCD	Kern County APCD
R	Primary Lead Smelters		X		X
S	Primary Aluminum Reduction Plants		X		X
T	Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants		X		X
U	Phosphate Fertilizer Industry: Superphosphoric Acid Plants		X		X
V	Phosphate Fertilizer Industry: Diammonium Phosphate Plants		X		X
W	Phosphate Fertilizer Industry: Triple Superphosphate Plants		X		X
X	Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities		X		X
Y	Coal Preparation Plants		X		X
Z	Ferroalloy Production Facilities		X		X
AA	Steel Plants: Electric Arc Furnaces Constructed After October 21, 1974 and On or Before August 17, 1983		X		X
AAa	Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After August 7, 1983		X		X
BB	Kraft pulp Mills		X		X
CC	Glass Manufacturing Plants		X		X
DD	Grain Elevators		X		X
EE	Surface Coating of Metal Furniture		X		X
FF	(Reserved)				
GG	Stationary Gas Turbines		X		X
HH	Lime Manufacturing Plants		X		X
KK	Lead-Acid Battery Manufacturing Plants		X		X
LL	Metallic Mineral Processing Plants		X		X
MM	Automobile and Light Duty Trucks Surface Coating Operations		X		X
NN	Phosphate Rock Plants		X		X

Delegation Status for New Source Performance Standards for Glenn County APCD, Great Basin Unified APCD, Imperial County APCD, and Kern County APCD

	Subpart	Air pollution control agency			
		Glenn County APCD	Great Basin Unified APCD	Imperial County APCD	Kern County APCD
PP	Ammonium Sulfate Manufacture		X		X
QQ	Graphic Arts Industry: Publication Rotogravure Printing		X		X
RR	Pressure Sensitive Tape and Label Surface Coating Operations		X		X
SS	Industrial Surface Coating: Large Appliances		X		X
TT	Metal Coil Surface Coating		X		X
UU	Asphalt Processing and Asphalt Roofing Manufacture		X		X
VV	Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry		X		X
WW	Beverage Can Surface Coating Industry		X		X
XX	Bulk Gasoline Terminals				
AAA	New Residential Wool Heaters		X		X
BBB	Rubber Tire Manufacturing Industry		X		X
CCC	(Reserved)				
DDD	Volatile Organic Compounds (VOC) Emissions from the Polymer Manufacturing Industry		X		X
EEE	(Reserved)				
FFF	Flexible Vinyl and Urethane Coating and Printing		X		X
GGG	Equipment Leaks of VOC in Petroleum Refineries		X		X
HHH	Synthetic Fiber Production Facilities		X		X
III	Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes		X		X
JJJ	Petroleum Dry Cleaners		X		X
KKK	Equipment Leaks of VOC From Onshore Natural Gas Processing Plants		X		X

Delegation Status for New Source Performance Standards for Glenn County APCD, Great Basin Unified APCD, Imperial County APCD, and Kern County APCD

	Subpart	Air pollution control agency			
		Glenn County APCD	Great Basin Unified APCD	Imperial County APCD	Kern County APCD
LLL	Onshore Natural Gas Processing: SO ₂ Emissions				X
MMM	(Reserved)				
NNN	Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations		X		X
OOO	Nonmetallic Mineral Processing Plants		X		X
PPP	Wool Fiberglass Insulation Manufacturing Plants		X		X
QQQ	VOC Emissions From Petroleum Refinery Wastewater Systems		X		X
RRR	Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes				X
SSS	Magnetic Tape Coating Facilities		X		X
TTT	Industrial Surface Coating: Surface Coating of Plastic Parts for Business Machines		X	X	
UUU	Calciners and Dryers in Mineral Industries		X		X
VVV	Polymeric Coating of Supporting Substrates Facilities		X		X
WWW	Municipal Solid Waste Landfills				X

(iv) Delegations for Lake County Air Quality Management District, Lassen County Air Pollution Control District, Mariposa County Air Pollution Control District, and Mendocino County Air Pollution Control District are shown in the following table:

Delegation Status for New Source Performance Standards for Lake County Air Quality Management District, Lassen County Air Pollution Control District, Mariposa County Air Pollution Control District, and Mendocino County Air Pollution Control District

	Subpart	Air pollution control agency			
		Lake County AQMD	Lassen County APCD	Mariposa County AQMD	Mendocino County AQMD
A	General Provisions	X			X

Delegation Status for New Source Performance Standards for Lake County Air Quality Management District, Lassen County Air Pollution Control District, Mariposa County Air Pollution Control District, and Mendocino County Air Pollution Control District

	Subpart	Air pollution control agency			
		Lake County AQMD	Lassen County APCD	Mariposa County AQMD	Mendocino County AQMD
D	Fossil-Fuel Fired Steam Generators Constructed After August 17, 1971	X			X
Da	Electric Utility Steam Generating Units Constructed After September 18, 1978	X			X
Db	Industrial-Commercial-Institutional Steam Generating Units	X			
Dc	Small Industrial Steam Generating Units	X			X
E	Incinerators	X			X
Ea	Municipal Waste Combustors Constructed After December 20, 1989 and On or Before September 20, 1994	X			X
Eb	Municipal Waste Combustors Constructed After September 20, 1994				
Ec	Hospital/Medical/Infectious Waste Incinerators for Which Construction is Commenced After June 20, 1996				
F	Portland Cement Plants	X			X
G	Nitric Acid Plants	X			X
H	Sulfuric Acid Plants	X			X
I	Hot Mix Asphalt Facilities	X			X
J	Petroleum Refineries	X			X
K	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978	X			X
Ka	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984	X			X
Kb	Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984	X			X

Delegation Status for New Source Performance Standards for Lake County Air Quality Management District, Lassen County Air Pollution Control District, Mariposa County Air Pollution Control District, and Mendocino County Air Pollution Control District

	Subpart	Air pollution control agency			
		Lake County AQMD	Lassen County APCD	Mariposa County AQMD	Mendocino County AQMD
L	Secondary Lead Smelters	X			X
M	Secondary Brass and Bronze Production Plants	X			X
N	Primary Emissions from Basic Oxygen Process Furnaces for Which Construction is Commenced After June 11, 1973	X			X
Na	Secondary Emissions from Basic Oxygen Process Steelmaking Facilities for Which Construction is Commenced After January 20, 1983	X			X
O	Sewage Treatment Plants	X			X
P	Primary Copper Smelters	X			X
Q	Primary Zinc Smelters	X			X
R	Primary Lead Smelters	X			X
S	Primary Aluminum Reduction Plants	X			X
T	Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants	X			X
U	Phosphate Fertilizer Industry: Superphosphoric Acid Plants	X			X
V	Phosphate Fertilizer Industry: Diammonium Phosphate Plants	X			X
W	Phosphate Fertilizer Industry: Triple Superphosphate Plants	X			X
X	Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities	X			X
Y	Coal Preparation Plants	X			X
Z	Ferroalloy Production Facilities	X			X
AA	Steel Plants: Electric Arc Furnaces Constructed After October 21, 1974 and On or Before August 17, 1983	X			X
AAa	Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After August 7, 1983	X			X

Delegation Status for New Source Performance Standards for Lake County Air Quality Management District, Lassen County Air Pollution Control District, Mariposa County Air Pollution Control District, and Mendocino County Air Pollution Control District

	Subpart	Air pollution control agency			
		Lake County AQMD	Lassen County APCD	Mariposa County AQMD	Mendocino County AQMD
BB	Kraft Pulp Mills	X			X
CC	Glass Manufacturing Plants	X			X
DD	Grain Elevators	X			X
EE	Surface Coating of Metal Furniture	X			X
FF	(Reserved)				
GG	Stationary Gas Turbines	X			X
HH	Lime Manufacturing Plants	X			X
KK	Lead-Acid Battery Manufacturing Plants	X			X
LL	Metallic Mineral Processing Plants	X			X
MM	Automobile and Light Duty Trucks Surface Coating Operations	X			X
NN	Phosphate Rock Plants	X			X
PP	Ammonium Sulfate Manufacture	X			X
QQ	Graphic Arts Industry: Publication Rotogravure Printing	X			X
RR	Pressure Sensitive Tape and Label Surface Coating Operations	X			X
SS	Industrial Surface Coating: Large Appliances	X			X
TT	Metal Coil Surface Coating	X			X
UU	Asphalt Processing and Asphalt Roofing Manufacture	X			X
VV	Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry	X			X
WW	Beverage Can Surface Coating Industry	X			X
XX	Bulk Gasoline Terminals				
AAA	New Residential Wood Heaters	X			X

Delegation Status for New Source Performance Standards for Lake County Air Quality Management District, Lassen County Air Pollution Control District, Mariposa County Air Pollution Control District, and Mendocino County Air Pollution Control District

	Subpart	Air pollution control agency			
		Lake County AQMD	Lassen County APCD	Mariposa County AQMD	Mendocino County AQMD
BBB	Rubber Tire Manufacturing Industry	X			X
CCC	(Reserved)				
DDD	Volatile Organic Compounds (VOC) Emissions from the Polymer Manufacturing Industry	X			X
EEE	(Reserved)				
FFF	Flexible Vinyl and Urethane Coating and Printing	X			X
GGG	Equipment Leaks of VOC in Petroleum Refineries	X			X
HHH	Synthetic Fiber Production Facilities	X			X
III	Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes	X			X
JJJ	Petroleum Dry Cleaners	X			X
KKK	Equipment Leaks of VOC From Onshore Natural Gas Processing Plants	X			X
LLL	Onshore Natural Gas Processing: SO ₂ Emissions	X			X
MMM	(Reserved)				
NNN	Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations	X			X
OOO	Nonmetallic Mineral Processing Plants	X			X
PPP	Wool Fiberglass Insulation Manufacturing Plants	X			X
QQQ	VOC Emissions From Petroleum Refinery Wastewater Systems	X			X
RRR	Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes	X			

Delegation Status for New Source Performance Standards for Lake County Air Quality Management District, Lassen County Air Pollution Control District, Mariposa County Air Pollution Control District, and Mendocino County Air Pollution Control District

	Subpart	Air pollution control agency			
		Lake County AQMD	Lassen County APCD	Mariposa County AQMD	Mendocino County AQMD
SSS	Magnetic Tape Coating Facilities	X			X
TTT	Industrial Surface Coating: Surface Coating of Plastic Parts for Business Machines				
UUU	Calciners and Dryers in Mineral Industries	X			X
VVV	Polymeric Coating of Supporting Substrates Facilities	X			X
WWW	Municipal Solid Waste Landfills	X			

(v) Delegations for Modoc Air Pollution Control District, Mojave Desert Air Quality Management District, Monterey Bay Unified Air Pollution Control District and North Coast Unified Air Quality Management District are shown in the following table:

Table 7 to Paragraph (d)(2)(v)—Delegation Status for New Source Performance Standards for Modoc County APCD, Mojave Desert AQMD, Monterey Bay Unified APCD, and North Coast Unified AQMD

	Subpart	Air pollution control agency			
		Modoc County APCD	Mojave Desert AQMD	Monterey Bay Unified APCD	North Coast Unified AQMD
A	General Provisions	X	X	X	X
D	Fossil-Fuel Fired Steam Generators Constructed After August 17, 1971	X	X	X	X
Da	Electric Utility Steam Generating Units Constructed After September 18, 1978	X	X	X	X
Db	Industrial-Commercial-Institutional Steam Generating Units	X	X	X	X
Dc	Small Industrial-Commercial-Institutional Steam Generating Units		X	X	
E	Incinerators	X	X	X	X
Ea	Municipal Waste Combustors Constructed After December 20, 1989 and On or Before September 20, 1994		X		
Eb	Large Municipal Waste Combustors Constructed After September 20, 1994		X		
Ec	Hospital/Medical/Infectious Waste Incinerators for Which Construction is		X		

Table 7 to Paragraph (d)(2)(v)—Delegation Status for New Source Performance Standards for Modoc County APCD, Mojave Desert AQMD, Monterey Bay Unified APCD, and North Coast Unified AQMD

	Subpart	Air pollution control agency			
		Modoc County APCD	Mojave Desert AQMD	Monterey Bay Unified APCD	North Coast Unified AQMD
	Commenced After June 20, 1996				
F	Portland Cement Plants	X	X	X	X
G	Nitric Acid Plants	X	X	X	X
Ga	Nitric Acid Plants For Which Construction, Reconstruction or Modification Commenced After October 14, 2011				
H	Sulfuric Acid Plant	X	X	X	X
I	Hot Mix Asphalt Facilities	X	X	X	X
J	Petroleum Refineries	X	X	X	X
Ja	Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007		X		
K	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978	X	X	X	X
Ka	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984	X	X	X	X
Kb	Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984	X	X	X	X
L	Secondary Lead Smelters	X	X	X	X
M	Secondary Brass and Bronze Production Plants	X	X	X	X
N	Primary Emissions from Basic Oxygen Process Furnaces for Which Construction is Commenced After June 11, 1973	X	X	X	X
Na	Secondary Emissions from Basic Oxygen Process Steelmaking Facilities for Which Construction is Commenced After January 20, 1983	X	X	X	X
O	Sewage Treatment Plants	X	X	X	X
P	Primary Copper Smelters	X	X	X	X

Table 7 to Paragraph (d)(2)(v)—Delegation Status for New Source Performance Standards for Modoc County APCD, Mojave Desert AQMD, Monterey Bay Unified APCD, and North Coast Unified AQMD

	Subpart	Air pollution control agency			
		Modoc County APCD	Mojave Desert AQMD	Monterey Bay Unified APCD	North Coast Unified AQMD
Q	Primary Zinc Smelters	X	X	X	X
R	Primary Lead Smelters	X	X	X	X
S	Primary Aluminum Reduction Plants	X	X	X	X
T	Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants	X	X	X	X
U	Phosphate Fertilizer Industry: Superphosphoric Acid Plants	X	X	X	X
V	Phosphate Fertilizer Industry: Diammonium Phosphate Plants	X	X	X	X
W	Phosphate Fertilizer Industry: Triple Superphosphate Plants	X	X	X	X
X	Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities	X	X	X	X
Y	Coal Preparation and Processing Plants	X	X	X	X
Z	Ferroalloy Production Facilities	X	X	X	X
AA	Steel Plants: Electric Arc Furnaces Constructed After October 21, 1974 and On or Before August 17, 1983	X	X	X	X
AAa	Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After August 7, 1983	X	X	X	X
BB	Kraft Pulp Mills	X	X	X	X
CC	Glass Manufacturing Plants	X	X	X	X
DD	Grain Elevators	X	X	X	X
EE	Surface Coating of Metal Furniture	X	X	X	X
FF	(Reserved)				
GG	Stationary Gas Turbines	X	X	X	X
HH	Lime Manufacturing Plants	X	X	X	X
KK	Lead-Acid Battery Manufacturing Plants	X	X	X	X
LL	Metallic Mineral Processing Plants	X	X	X	X

Table 7 to Paragraph (d)(2)(v)—Delegation Status for New Source Performance Standards for Modoc County APCD, Mojave Desert AQMD, Monterey Bay Unified APCD, and North Coast Unified AQMD

	Subpart	Air pollution control agency			
		Modoc County APCD	Mojave Desert AQMD	Monterey Bay Unified APCD	North Coast Unified AQMD
MM	Automobile and Light Duty Trucks Surface Coating Operations	X	X	X	X
NN	Phosphate Rock Plants	X	X	X	X
PP	Ammonium Sulfate Manufacture	X	X	X	X
QQ	Graphic Arts Industry: Publication Rotogravure Printing	X	X	X	X
RR	Pressure Sensitive Tape and Label Surface Coating Operations	X	X	X	X
SS	Industrial Surface Coating: Large Appliances	X	X	X	X
TT	Metal Coil Surface Coating	X	X	X	X
UU	Asphalt Processing and Asphalt Roofing Manufacture	X	X	X	X
VV	Equipment Leaks of VOC in the Synthetic Organic Industry Chemicals Manufacturing	X	X	X	X
VVa	Equipment Leaks of VOC in the Synthetic Organic Industry for Which Construction, Reconstruction, or Chemicals Manufacturing Modification Commenced After November 7, 2006		X		
WW	Beverage Can Surface Coating Industry	X	X	X	X
XX	Bulk Gasoline Terminals				
AAA	New Residential Wood Heaters	X	X	X	X
BBB	Rubber Tire Manufacturing Industry	X	X	X	X
CCC	(Reserved)				
DDD	Volatile Organic Compounds (VOC) Emissions from the Polymer Manufacturing Industry	X	X	X	
EEE	(Reserved)				
FFF	Flexible Vinyl and Urethane Coating and Printing	X	X	X	X
GGG	Equipment Leaks of VOC in Petroleum Refineries	X	X	X	X
GGGa	Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006		X		

Table 7 to Paragraph (d)(2)(v)—Delegation Status for New Source Performance Standards for Modoc County APCD, Mojave Desert AQMD, Monterey Bay Unified APCD, and North Coast Unified AQMD

	Subpart	Air pollution control agency			
		Modoc County APCD	Mojave Desert AQMD	Monterey Bay Unified APCD	North Coast Unified AQMD
HHH	Synthetic Fiber Production Facilities	X	X	X	X
III	Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes		X		
JJJ	Petroleum Dry Cleaners	X	X	X	X
KKK	Equipment Leaks of VOC From Onshore Natural Gas Processing Plants	X	X	X	X
LLL	Onshore Natural Gas Processing: SO ₂ Emissions	X	X	X	X
MMM	(Reserved)				
NNN	Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations	X	X	X	
OOO	Nonmetallic Mineral Processing Plants	X	X	X	X
PPP	Wool Fiberglass Insulation Manufacturing Plants	X	X	X	X
QQQ	VOC Emissions From Petroleum Refinery Wastewater Systems	X	X	X	X
RRR	Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes		X		
SSS	Magnetic Tape Coating Facilities	X	X	X	X
TTT	Industrial Surface Coating: Surface Coating of Plastic Parts for Business Machines	X	X	X	X
UUU	Calciners and Dryers in Mineral Industries		X	X	
VVV	Polymeric Coating of Supporting Substrates Facilities		X	X	X
WWW	Municipal Solid Waste Landfills		X	X	
AAAA	Small Municipal Waste Combustion Units for Which Construction is Commenced After August 30, 1999 or for Which Modification or Reconstruction is Commenced After June 6, 2001		X		
CCCC	Commercial and Industrial Solid Waste Incineration Units for Which Construction Is Commenced After November 30, 1999 or for Which Modification or Reconstruction Is Commenced on or After June 1, 2001		X		

Table 7 to Paragraph (d)(2)(v)—Delegation Status for New Source Performance Standards for Modoc County APCD, Mojave Desert AQMD, Monterey Bay Unified APCD, and North Coast Unified AQMD

	Subpart	Air pollution control agency			
		Modoc County APCD	Mojave Desert AQMD	Monterey Bay Unified APCD	North Coast Unified AQMD
EEEE	Other Solid Waste Incineration Units for Which Construction is Commenced After December 9, 2004, or for Which Modification or Reconstruction is Commenced on or After June 16, 2006		X		
GGGG	(Reserved)				
HHHH	(Reserved)				
IIII	Stationary Compression Ignition Internal Combustion Engines		X	X	
JJJJ	Stationary Spark Ignition Internal Combustion Engines		X	X	
KKKK	Stationary Combustion Turbines		X	X	
LLLL	New Sewage Sludge Incineration Units				
OOOO	Crude Oil and Natural Gas Production, Transmission, and Distribution				

(vi) Delegations for Northern Sierra Air Quality Management District, Northern Sonoma County Air Pollution Control District, Placer County Air Pollution Control District, and Sacramento Metropolitan Air Quality Management District are shown in the following table:

Delegation Status for New Source Performance Standards for Northern Sierra Air Quality Management District, Northern Sonoma County Air Pollution Control District, Placer County Air Pollution Control District, and Sacramento Metropolitan Air Quality Management District

	Subpart	Air pollution control agency			
		Northern Sierra AQMD	Northern Sonoma County APCD	Placer County APCD	Sacramento Metropolitan AQMD
A	General Provisions		X		X
D	Fossil-Fuel Fired Steam Generators Constructed After August 17, 1971		X		X
Da	Electric Utility Steam Generating Units Constructed After September 18, 1978		X		X
Db	Industrial-Commercial-Institutional Steam Generating Units				X

Delegation Status for New Source Performance Standards for Northern Sierra Air Quality Management District, Northern Sonoma County Air Pollution Control District, Placer County Air Pollution Control District, and Sacramento Metropolitan Air Quality Management District

	Subpart	Air pollution control agency			
		Northern Sierra AQMD	Northern Sonoma County APCD	Placer County APCD	Sacramento Metropolitan AQMD
Dc	Small Industrial Steam Generating Units				X
E	Incinerators		X		X
Ea	Municipal Waste Combustors Constructed After December 20, 1989 and On or Before September 20, 1994				X
Eb	Municipal Waste Combustors Constructed After September 20, 1994				X
Ec	Hospital/Medical/Infectious Waste Incinerators for Which Construction is Commenced After June 20, 1996				X
F	Portland Cement Plants		X		X
G	Nitric Acid Plants		X		X
H	Sulfuric Acid Plants		X		X
I	Hot Mix Asphalt Facilities		X		X
J	Petroleum Refineries		X		X
K	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978		X		X
Ka	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984		X		X
Kb	Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984				X
L	Secondary Lead Smelters		X		X
M	Secondary Brass and Bronze Production Plants		X		X

Delegation Status for New Source Performance Standards for Northern Sierra Air Quality Management District, Northern Sonoma County Air Pollution Control District, Placer County Air Pollution Control District, and Sacramento Metropolitan Air Quality Management District

	Subpart	Air pollution control agency			
		Northern Sierra AQMD	Northern Sonoma County APCD	Placer County APCD	Sacramento Metropolitan AQMD
N	Primary Emissions from Basic Oxygen Process Furnaces for Which Construction is Commenced After June 11, 1973		X		X
Na	Secondary Emissions from Basic Oxygen Process Steelmaking Facilities for Which Construction is Commenced After January 20, 1983				X
O	Sewage Treatment Plants		X		X
P	Primary Copper Smelters		X		X
Q	Primary Zinc Smelters		X		X
R	Primary Lead Smelters		X		X
S	Primary Aluminum Reduction Plants		X		X
T	Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants		X		X
U	Phosphate Fertilizer Industry: Superphosphoric Acid Plants		X		X
V	Phosphate Fertilizer Industry: Diammonium Phosphate Plants		X		X
W	Phosphate Fertilizer Industry: Triple Superphosphate Plants		X		X
X	Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities		X		X
Y	Coal Preparation Plants		X		X
Z	Ferroalloy Production Facilities		X		X
AA	Steel Plants: Electric Arc Furnaces Constructed After October 21, 1974 and On or Before August 17, 1983		X		X
AAa	Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After August 7, 1983				X

Delegation Status for New Source Performance Standards for Northern Sierra Air Quality Management District, Northern Sonoma County Air Pollution Control District, Placer County Air Pollution Control District, and Sacramento Metropolitan Air Quality Management District

	Subpart	Air pollution control agency			
		Northern Sierra AQMD	Northern Sonoma County APCD	Placer County APCD	Sacramento Metropolitan AQMD
BB	Kraft pulp Mills		X		X
CC	Glass Manufacturing Plants		X		X
DD	Grain Elevators		X		X
EE	Surface Coating of Metal Furniture				X
FF	(Reserved)				
GG	Stationary Gas Turbines		X		X
HH	Lime Manufacturing Plants		X		X
KK	Lead-Acid Battery Manufacturing Plants				X
LL	Metallic Mineral Processing Plants				X
MM	Automobile and Light Duty Trucks Surface Coating Operations		X		X
NN	Phosphate Rock Plants				X
PP	Ammonium Sulfate Manufacture		X		X
QQ	Graphic Arts Industry: Publication Rotogravure Printing				X
RR	Pressure Sensitive Tape and Label Surface Coating Operations				X
SS	Industrial Surface Coating: Large Appliances				X
TT	Metal Coil Surface Coating				X
UU	Asphalt Processing and Asphalt Roofing Manufacture				X
VV	Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry				X
WW	Beverage Can Surface Coating Industry				X
XX	Bulk Gasoline Terminals				
AAA	New Residential Wool Heaters				X

Delegation Status for New Source Performance Standards for Northern Sierra Air Quality Management District, Northern Sonoma County Air Pollution Control District, Placer County Air Pollution Control District, and Sacramento Metropolitan Air Quality Management District

	Subpart	Air pollution control agency			
		Northern Sierra AQMD	Northern Sonoma County APCD	Placer County APCD	Sacramento Metropolitan AQMD
BBB	Rubber Tire Manufacturing Industry				X
CCC	(Reserved)				
DDD	Volatile Organic Compounds (VOC) Emissions from the Polymer Manufacturing Industry				X
EEE	(Reserved)				
FFF	Flexible Vinyl and Urethane Coating and Printing				X
GGG	Equipment Leaks of VOC in Petroleum Refineries				X
HHH	Synthetic Fiber Production Facilities				X
III	Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes				X
JJJ	Petroleum Dry Cleaners				X
KKK	Equipment Leaks of VOC From Onshore Natural Gas Processing Plants				X
LLL	Onshore Natural Gas Processing: SO ₂ Emissions				X
MMM	(Reserved)				
NNN	Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations				X
OOO	Nonmetallic Mineral Processing Plants				X
PPP	Wool Fiberglass Insulation Manufacturing Plants				X
QQQ	VOC Emissions From Petroleum Refinery Wastewater Systems				X
RRR	Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes				X

Delegation Status for New Source Performance Standards for Northern Sierra Air Quality Management District, Northern Sonoma County Air Pollution Control District, Placer County Air Pollution Control District, and Sacramento Metropolitan Air Quality Management District

	Subpart	Air pollution control agency			
		Northern Sierra AQMD	Northern Sonoma County APCD	Placer County APCD	Sacramento Metropolitan AQMD
SSS	Magnetic Tape Coating Facilities				X
TTT	Industrial Surface Coating: Surface Coating of Plastic Parts for Business Machines				X
UUU	Calciners and Dryers in Mineral Industries				X
VVV	Polymeric Coating of Supporting Substrates Facilities				X
WWW	Municipal Solid Waste Landfills				X

(vii) Delegations for San Diego County Air Pollution Control District, San Joaquin Valley Unified Air Pollution Control District, San Luis Obispo County Air Pollution Control District, and Santa Barbara County Air Pollution Control District are shown in the following table:

Table 9 to Paragraph (d)(2)(vii)—Delegation Status for New Source Performance Standards for San Diego County APCD, San Joaquin Valley Unified APCD, San Luis Obispo County APCD, and Santa Barbara County APCD

	Subpart	Air pollution control agency			
		San Diego County APCD	San Joaquin Valley Unified APCD	San Luis Obispo County APCD	Santa Barbara County APCD
A	General Provisions	X	X	X	X
D	Fossil-Fuel Fired Steam Generators Constructed After August 17, 1971	X	X	X	X
Da	Electric Utility Steam Generating Units Constructed After September 18, 1978	X	X	X	X
Db	Industrial-Commercial-Institutional Steam Generating Units	X	X	X	X
Dc	Small Industrial-Commercial-Institutional Steam Generating Units	X	X	X	X
E	Incinerators	X	X	X	X
Ea	Municipal Waste Combustors Constructed After December 20, 1989 and On or Before September 20, 1994	X	X	X	
Eb	Large Municipal Waste Combustors Constructed After September 20, 1994	X	X		X

Table 9 to Paragraph (d)(2)(vii)—Delegation Status for New Source Performance Standards for San Diego County APCD, San Joaquin Valley Unified APCD, San Luis Obispo County APCD, and Santa Barbara County APCD

	Subpart	Air pollution control agency			
		San Diego County APCD	San Joaquin Valley Unified APCD	San Luis Obispo County APCD	Santa Barbara County APCD
Ec	Hospital/Medical/Infectious Waste Incinerators for Which Construction is Commenced After June 20, 1996	X			X
F	Portland Cement Plants	X	X	X	
G	Nitric Acid Plants	X	X	X	
Ga	Nitric Acid Plants For Which Construction, Reconstruction or Modification Commenced After October 14, 2011				
H	Sulfuric Acid Plant	X	X	X	
I	Hot Mix Asphalt Facilities	X	X	X	X
J	Petroleum Refineries	X	X	X	X
Ja	Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007				X
K	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978	X	X	X	X
Ka	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984	X	X	X	X
Kb	Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984	X	X	X	X
L	Secondary Lead Smelters	X	X	X	X
M	Secondary Brass and Bronze Production Plants	X	X	X	X
N	Primary Emissions from Basic Oxygen Process Furnaces for Which Construction is Commenced After June 11, 1973	X	X	X	
Na	Secondary Emissions from Basic Oxygen Process Steelmaking Facilities for Which Construction is Commenced After January 20, 1983	X	X	X	
O	Sewage Treatment Plants	X	X	X	X
P	Primary Copper Smelters	X	X	X	

Table 9 to Paragraph (d)(2)(vii)—Delegation Status for New Source Performance Standards for San Diego County APCD, San Joaquin Valley Unified APCD, San Luis Obispo County APCD, and Santa Barbara County APCD

	Subpart	Air pollution control agency			
		San Diego County APCD	San Joaquin Valley Unified APCD	San Luis Obispo County APCD	Santa Barbara County APCD
Q	Primary Zinc Smelters	X	X	X	
R	Primary Lead Smelters	X	X	X	
S	Primary Aluminum Reduction Plants	X	X	X	
T	Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants	X	X	X	
U	Phosphate Fertilizer Industry: Superphosphoric Acid Plants	X	X	X	
V	Phosphate Fertilizer Industry: Diammonium Phosphate Plants	X	X	X	
W	Phosphate Fertilizer Industry: Triple Superphosphate Plants	X	X	X	
X	Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities	X	X	X	
Y	Coal Preparation and Processing Plants	X	X	X	
Z	Ferroalloy Production Facilities	X	X	X	
AA	Steel Plants: Electric Arc Furnaces Constructed After October 21, 1974 and On or Before August 17, 1983	X	X	X	
AAa	Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After August 7, 1983	X	X	X	
BB	Kraft Pulp Mills	X	X	X	
CC	Glass Manufacturing Plants	X	X	X	X
DD	Grain Elevators	X	X	X	X
EE	Surface Coating of Metal Furniture	X	X	X	
FF	(Reserved)				
GG	Stationary Gas Turbines	X	X	X	X
HH	Lime Manufacturing Plants	X	X	X	
KK	Lead-Acid Battery Manufacturing Plants	X	X	X	

Table 9 to Paragraph (d)(2)(vii)—Delegation Status for New Source Performance Standards for San Diego County APCD, San Joaquin Valley Unified APCD, San Luis Obispo County APCD, and Santa Barbara County APCD

	Subpart	Air pollution control agency			
		San Diego County APCD	San Joaquin Valley Unified APCD	San Luis Obispo County APCD	Santa Barbara County APCD
LL	Metallic Mineral Processing Plants	X	X	X	
MM	Automobile and Light Duty Trucks Surface Coating Operations	X	X	X	
NN	Phosphate Rock Plants	X	X	X	
PP	Ammonium Sulfate Manufacture	X	X	X	
QQ	Graphic Arts Industry: Publication Rotogravure Printing	X	X	X	
RR	Pressure Sensitive Tape and Label Surface Coating Operations	X	X	X	
SS	Industrial Surface Coating: Large Appliances	X	X	X	
TT	Metal Coil Surface Coating	X	X	X	
UU	Asphalt Processing and Asphalt Roofing Manufacture	X	X	X	
VV	Equipment Leaks of VOC in the Synthetic Organic Industry Chemicals Manufacturing	X	X	X	
VVa	Equipment Leaks of VOC in the Synthetic Organic Industry for Which Construction, Reconstruction, or Chemicals Manufacturing Modification Commenced After November 7, 2006				X
WW	Beverage Can Surface Coating Industry	X	X	X	
XX	Bulk Gasoline Terminals				
AAA	New Residential Wood Heaters	X	X	X	X
BBB	Rubber Tire Manufacturing Industry	X	X	X	
CCC	(Reserved)				
DDD	Volatile Organic Compounds (VOC) Emissions from the Polymer Manufacturing Industry	X	X		
EEE	(Reserved)				
FFF	Flexible Vinyl and Urethane Coating and Printing	X	X	X	
GGG	Equipment Leaks of VOC in Petroleum Refineries	X	X	X	

Table 9 to Paragraph (d)(2)(vii)—Delegation Status for New Source Performance Standards for San Diego County APCD, San Joaquin Valley Unified APCD, San Luis Obispo County APCD, and Santa Barbara County APCD

	Subpart	Air pollution control agency			
		San Diego County APCD	San Joaquin Valley Unified APCD	San Luis Obispo County APCD	Santa Barbara County APCD
GGGa	Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006				X
HHH	Synthetic Fiber Production Facilities	X	X	X	
III	Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes	X	X		
JJJ	Petroleum Dry Cleaners	X	X	X	
KKK	Equipment Leaks of VOC From Onshore Natural Gas Processing Plants	X	X	X	
LLL	Onshore Natural Gas Processing: SO ₂ Emissions	X	X	X	
MMM	(Reserved)				
NNN	Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations	X	X		
OOO	Nonmetallic Mineral Processing Plants	X	X	X	X
PPP	Wool Fiberglass Insulation Manufacturing Plants	X	X	X	
QQQ	VOC Emissions From Petroleum Refinery Wastewater Systems	X	X	X	
RRR	Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes	X	X	X	
SSS	Magnetic Tape Coating Facilities	X	X	X	
TTT	Industrial Surface Coating: Surface Coating of Plastic Parts for Business Machines	X	X	X	
UUU	Calciners and Dryers in Mineral Industries	X	X	X	X
VVV	Polymeric Coating of Supporting Substrates Facilities	X	X	X	X
WWW	Municipal Solid Waste Landfills	X	X	X	X
AAAA	Small Municipal Waste Combustion Units for Which Construction is Commenced After August 30, 1999 or for Which Modification or Reconstruction is Commenced After June 6, 2001	X			X

Table 9 to Paragraph (d)(2)(vii)—Delegation Status for New Source Performance Standards for San Diego County APCD, San Joaquin Valley Unified APCD, San Luis Obispo County APCD, and Santa Barbara County APCD

	Subpart	Air pollution control agency			
		San Diego County APCD	San Joaquin Valley Unified APCD	San Luis Obispo County APCD	Santa Barbara County APCD
CCCC	Commercial and Industrial Solid Waste Incineration Units for Which Construction Is Commenced After November 30, 1999 or for Which Modification or Reconstruction Is Commenced on or After June 1, 2001	X			X
EEEE	Other Solid Waste Incineration Units for Which Construction is Commenced After December 9, 2004, or for Which Modification or Reconstruction is Commenced on or After June 16, 2006	X			X
GGGG	(Reserved)				
HHHH	(Reserved)				
IIII	Stationary Compression Ignition Internal Combustion Engines	X			X
JJJJ	Stationary Spark Ignition Internal Combustion Engines	X			X
KKKK	Stationary Combustion Turbines	X			X
LLLL	New Sewage Sludge Incineration Units				
OOOO	Crude Oil and Natural Gas Production, Transmission, and Distribution				
QQQQ	Standards of Performance for New Residential Hydronic Heaters and Forced-Air Furnaces	X			
TTTT	Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units	X			

(viii) Delegations for Shasta County Air Quality Management District, Siskiyou County Air Pollution Control District, South Coast Air Quality Management District, and Tehama County Air Pollution Control District are shown in the following table:

Delegation Status for New Source Performance Standards for Shasta County AQMD, Siskiyou County APCD, South Coast AQMD, and Tehama County APCD

	Subpart	Air pollution control agency			
		Shasta County AQMD	Siskiyou County APCD	South Coast AQMD	Tehama County APCD
A	General Provisions	X	X	X	

Delegation Status for New Source Performance Standards for Shasta County AQMD, Siskiyou County APCD, South Coast AQMD, and Tehama County APCD

	Subpart	Air pollution control agency			
		Shasta County AQMD	Siskiyou County APCD	South Coast AQMD	Tehama County APCD
D	Fossil-Fuel Fired Steam Generators Constructed After August 17, 1971	X		X	
Da	Electric Utility Steam Generating Units Constructed After September 18, 1978			X	
Db	Industrial-Commercial-Institutional Steam Generating Units			X	
Dc	Small Industrial-Commercial-Institutional Steam Generating Units			X	
E	Incinerators	X		X	
Ea	Municipal Waste Combustors Constructed After December 20, 1989 and On or Before September 20, 1994			X	
Eb	Large Municipal Waste Combustors Constructed After September 20, 1994			X	
Ec	Hospital/Medical/Infectious Waste Incinerators for Which Construction is Commenced After June 20, 1996			X	
F	Portland Cement Plants	X		X	
G	Nitric Acid Plants	X		X	
Ga	Nitric Acid Plants For Which Construction, Reconstruction or Modification Commenced After October 14, 2011				
H	Sulfuric Acid Plant	X		X	
I	Hot Mix Asphalt Facilities	X		X	
J	Petroleum Refineries	X		X	
Ja	Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007			X	
K	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978	X		X	
Ka	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984			X	

Delegation Status for New Source Performance Standards for Shasta County AQMD, Siskiyou County APCD, South Coast AQMD, and Tehama County APCD

	Subpart	Air pollution control agency			
		Shasta County AQMD	Siskiyou County APCD	South Coast AQMD	Tehama County APCD
Kb	Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984			X	
L	Secondary Lead Smelters	X		X	
M	Secondary Brass and Bronze Production Plants	X		X	
N	Primary Emissions from Basic Oxygen Process Furnaces for Which Construction is Commenced After June 11, 1973	X		X	
Na	Secondary Emissions from Basic Oxygen Process Steelmaking Facilities for Which Construction is Commenced After January 20, 1983			X	
O	Sewage Treatment Plants	X		X	
P	Primary Copper Smelters	X		X	
Q	Primary Zinc Smelters	X		X	
R	Primary Lead Smelters	X		X	
S	Primary Aluminum Reduction Plants	X		X	
T	Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants	X		X	
U	Phosphate Fertilizer Industry: Superphosphoric Acid Plants	X		X	
V	Phosphate Fertilizer Industry: Diammonium Phosphate Plants	X		X	
W	Phosphate Fertilizer Industry: Triple Superphosphate Plants	X		X	
X	Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities	X		X	
Y	Coal Preparation and Processing Plants	X		X	
Z	Ferroalloy Production Facilities	X		X	
AA	Steel Plants: Electric Arc Furnaces Constructed After October 21, 1974 and On or Before August 17, 1983	X		X	
AAa	Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After August 7, 1983			X	

Delegation Status for New Source Performance Standards for Shasta County AQMD, Siskiyou County APCD, South Coast AQMD, and Tehama County APCD

	Subpart	Air pollution control agency			
		Shasta County AQMD	Siskiyou County APCD	South Coast AQMD	Tehama County APCD
BB	Kraft Pulp Mills	X		X	
CC	Glass Manufacturing Plants			X	
DD	Grain Elevators	X		X	
EE	Surface Coating of Metal Furniture			X	
FF	(Reserved)				
GG	Stationary Gas Turbines			X	
HH	Lime Manufacturing Plants	X		X	
KK	Lead-Acid Battery Manufacturing Plants			X	
LL	Metallic Mineral Processing Plants			X	
MM	Automobile and Light Duty Trucks Surface Coating Operations			X	
NN	Phosphate Rock Plants			X	
PP	Ammonium Sulfate Manufacture			X	
QQ	Graphic Arts Industry: Publication Rotogravure Printing			X	
RR	Pressure Sensitive Tape and Label Surface Coating Operations			X	
SS	Industrial Surface Coating: Large Appliances			X	
TT	Metal Coil Surface Coating			X	
UU	Asphalt Processing and Asphalt Roofing Manufacture			X	
VV	Equipment Leaks of VOC in the Synthetic Organic Industry Chemicals Manufacturing			X	
VVa	Equipment Leaks of VOC in the Synthetic Organic Industry for Which Construction, Reconstruction, or Chemicals Manufacturing Modification Commenced After November 7, 2006			X	
WW	Beverage Can Surface Coating Industry			X	
XX	Bulk Gasoline Terminals				
AAA	New Residential Wood Heaters		X	X	

Delegation Status for New Source Performance Standards for Shasta County AQMD, Siskiyou County APCD, South Coast AQMD, and Tehama County APCD

	Subpart	Air pollution control agency			
		Shasta County AQMD	Siskiyou County APCD	South Coast AQMD	Tehama County APCD
BBB	Rubber Tire Manufacturing Industry		X	X	
CCC	(Reserved)				
DDD	Volatile Organic Compounds (VOC) Emissions from the Polymer Manufacturing Industry			X	
EEE	(Reserved)				
FFF	Flexible Vinyl and Urethane Coating and Printing			X	
GGG	Equipment Leaks of VOC in Petroleum Refineries			X	
GGGa	Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006			X	
HHH	Synthetic Fiber Production Facilities			X	
III	Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes			X	
JJJ	Petroleum Dry Cleaners			X	
KKK	Equipment Leaks of VOC From Onshore Natural Gas Processing Plants			X	
LLL	Onshore Natural Gas Processing: SO ₂ Emissions			X	
MMM	(Reserved)				
NNN	Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations			X	
OOO	Nonmetallic Mineral Processing Plants			X	
PPP	Wool Fiberglass Insulation Manufacturing Plants			X	
QQQ	VOC Emissions From Petroleum Refinery Wastewater Systems		X	X	
RRR	Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes			X	
SSS	Magnetic Tape Coating Facilities		X	X	

Delegation Status for New Source Performance Standards for Shasta County AQMD, Siskiyou County APCD, South Coast AQMD, and Tehama County APCD

	Subpart	Air pollution control agency			
		Shasta County AQMD	Siskiyou County APCD	South Coast AQMD	Tehama County APCD
TTT	Industrial Surface Coating: Surface Coating of Plastic Parts for Business Machines		X	X	
UUU	Calciners and Dryers in Mineral Industries			X	
VVV	Polymeric Coating of Supporting Substrates Facilities			X	
WWW	Municipal Solid Waste Landfills			X	
AAAA	Small Municipal Waste Combustion Units for Which Construction is Commenced After August 30, 1999 or for Which Modification or Reconstruction is Commenced After June 6, 2001	X	X	X	
CCCC	Commercial and Industrial Solid Waste Incineration Units for Which Construction Is Commenced After November 30, 1999 or for Which Modification or Reconstruction Is Commenced on or After June 1, 2001			X	
EEEE	Other Solid Waste Incineration Units for Which Construction is Commenced After December 9, 2004, or for Which Modification or Reconstruction is Commenced on or After June 16, 2006			X	
GGGG	(Reserved)				
HHHH	(Reserved)				
IIII	Stationary Compression Ignition Internal Combustion Engines			X	
JJJJ	Stationary Spark Ignition Internal Combustion Engines			X	
KKKK	Stationary Combustion Turbines			X	
LLLL	New Sewage Sludge Incineration Units				
OOOO	Crude Oil and Natural Gas Production, Transmission, and Distribution				

(ix) Delegations for Tuolumne County Air Pollution Control District, Ventura County Air Pollution Control District, and Yolo-Solano Air Quality Management District are shown in the following table:

Table 11 to Paragraph (d)(2)(ix)—Delegation Status for New Source Performance Standards for Tuolumne County APCD, Ventura County APCD, and Yolo-Solano AQMD

Permit Issued: [month day, year]

Permit Expires: [month day, year]

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	Subpart	Air pollution control agency		
		Tuolumne County APCD	Ventura County APCD	Yolo-Solano AQMD
A	General Provisions		X	X
D	Fossil-Fuel Fired Steam Generators Constructed After August 17, 1971		X	X
Da	Electric Utility Steam Generating Units Constructed After September 18, 1978		X	
Db	Industrial-Commercial-Institutional Steam Generating Units		X	X
Dc	Small Industrial-Commercial-Institutional Steam Generating Units		X	
E	Incinerators		X	
Ea	Municipal Waste Combustors Constructed After December 20, 1989 and On or Before September 20, 1994		X	
Eb	Large Municipal Waste Combustors Constructed After September 20, 1994			
Ec	Hospital/Medical/Infectious Waste Incinerators for Which Construction is Commenced After June 20, 1996			
F	Portland Cement Plants		X	
G	Nitric Acid Plants		X	
H	Sulfuric Acid Plant		X	
I	Hot Mix Asphalt Facilities		X	X
J	Petroleum Refineries		X	X
K	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978		X	X
Ka	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984		X	
Kb	Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984		X	
L	Secondary Lead Smelters		X	
M	Secondary Brass and Bronze Production Plants		X	
N	Primary Emissions from Basic Oxygen Process Furnaces for Which Construction is Commenced After June 11, 1973		X	

Table 11 to Paragraph (d)(2)(ix)—Delegation Status for New Source Performance Standards for Tuolumne County APCD, Ventura County APCD, and Yolo-Solano AQMD

	Subpart	Air pollution control agency		
		Tuolumne County APCD	Ventura County APCD	Yolo-Solano AQMD
Na	Secondary Emissions from Basic Oxygen Process Steelmaking Facilities for Which Construction is Commenced After January 20, 1983		X	
O	Sewage Treatment Plants		X	
P	Primary Copper Smelters		X	
Q	Primary Zinc Smelters		X	
R	Primary Lead Smelters		X	
S	Primary Aluminum Reduction Plants		X	
T	Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants		X	
U	Phosphate Fertilizer Industry: Superphosphoric Acid Plants		X	
V	Phosphate Fertilizer Industry: Diammonium Phosphate Plants		X	
W	Phosphate Fertilizer Industry: Triple Superphosphate Plants		X	
X	Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities		X	
Y	Coal Preparation and Processing Plants		X	
Z	Ferroalloy Production Facilities		X	
AA	Steel Plants: Electric Arc Furnaces Constructed After October 21, 1974 and On or Before August 17, 1983		X	X
AAa	Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After August 7, 1983		X	
BB	Kraft Pulp Mills		X	
CC	Glass Manufacturing Plants		X	
DD	Grain Elevators		X	
EE	Surface Coating of Metal Furniture		X	
FF	(Reserved)			
GG	Stationary Gas Turbines		X	

Table 11 to Paragraph (d)(2)(ix)—Delegation Status for New Source Performance Standards for Tuolumne County APCD, Ventura County APCD, and Yolo-Solano AQMD

	Subpart	Air pollution control agency		
		Tuolumne County APCD	Ventura County APCD	Yolo-Solano AQMD
HH	Lime Manufacturing Plants		X	
KK	Lead-Acid Battery Manufacturing Plants		X	
LL	Metallic Mineral Processing Plants		X	
MM	Automobile and Light Duty Trucks Surface Coating Operations		X	
NN	Phosphate Rock Plants		X	
PP	Ammonium Sulfate Manufacture		X	
QQ	Graphic Arts Industry: Publication Rotogravure Printing		X	
RR	Pressure Sensitive Tape and Label Surface Coating Operations		X	
SS	Industrial Surface Coating: Large Appliances		X	
TT	Metal Coil Surface Coating		X	
UU	Asphalt Processing and Asphalt Roofing Manufacture		X	
VV	Equipment Leaks of VOC in the Synthetic Organic Industry Chemicals Manufacturing		X	
WW	Beverage Can Surface Coating Industry		X	
XX	Bulk Gasoline Terminals			
AAA	New Residential Wood Heaters		X	
BBB	Rubber Tire Manufacturing Industry		X	
CCC	(Reserved)			
DDD	Volatile Organic Compounds (VOC) Emissions from the Polymer Manufacturing Industry		X	
EEE	(Reserved)			
FFF	Flexible Vinyl and Urethane Coating and Printing		X	
GGG	Equipment Leaks of VOC in Petroleum Refineries		X	
GGGa	Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006			

Table 11 to Paragraph (d)(2)(ix)—Delegation Status for New Source Performance Standards for Tuolumne County APCD, Ventura County APCD, and Yolo-Solano AQMD

	Subpart	Air pollution control agency		
		Tuolumne County APCD	Ventura County APCD	Yolo-Solano AQMD
HHH	Synthetic Fiber Production Facilities		X	
III	Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes		X	
JJJ	Petroleum Dry Cleaners		X	
KKK	Equipment Leaks of VOC From Onshore Natural Gas Processing Plants		X	
LLL	Onshore Natural Gas Processing: SO ₂ Emissions		X	
MMM	(Reserved)			
NNN	Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations		X	
OOO	Nonmetallic Mineral Processing Plants		X	X
PPP	Wool Fiberglass Insulation Manufacturing Plants		X	
QQQ	VOC Emissions From Petroleum Refinery Wastewater Systems		X	
RRR	Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes		X	
SSS	Magnetic Tape Coating Facilities		X	
TTT	Industrial Surface Coating: Surface Coating of Plastic Parts for Business Machines		X	
UUU	Calciners and Dryers in Mineral Industries		X	
VVV	Polymeric Coating of Supporting Substrates Facilities		X	
WWW	Municipal Solid Waste Landfills	X	X	

(3) *Hawaii*. The following table identifies delegations for Hawaii:

Delegation Status for New Source Performance Standards for Hawaii:

Delegation Status for New Source Performance Standards for Hawaii		
	Subpart	Hawaii
A	General Provisions	X

Delegation Status for New Source Performance Standards for Hawaii

	Subpart	Hawaii
D	Fossil-Fuel Fired Steam Generators Constructed After August 17, 1971	X
Da	Electric Utility Steam Generating Units Constructed After September 18, 1978	X
Db	Industrial-Commercial-Institutional Steam Generating Units	X
Dc	Small Industrial Steam Generating Units	X
E	Incinerators	X
Ea	Municipal Waste Combustors Constructed After December 20, 1989 and On or Before September 20, 1994	X
Eb	Municipal Waste Combustors Constructed After September 20, 1994	X
Ec	Hospital/Medical/Infectious Waste Incinerators for Which Construction is Commenced After June 20, 1996	X
F	Portland Cement Plants	X
G	Nitric Acid Plants	
H	Sulfuric Acid Plants	
I	Hot Mix Asphalt Facilities	X
J	Petroleum Refineries	X
Ja	Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007	
K	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978	X
Ka	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984	X
Kb	Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984	X
L	Secondary Lead Smelters	
M	Secondary Brass and Bronze Production Plants	
N	Primary Emissions from Basic Oxygen Process Furnaces for Which Construction is Commenced After June 11, 1973	
Na	Secondary Emissions from Basic Oxygen Process Steelmaking Facilities for Which Construction is Commenced After January 20, 1983	

Delegation Status for New Source Performance Standards for Hawaii		
	Subpart	Hawaii
O	Sewage Treatment Plants	X
P	Primary Copper Smelters	
Q	Primary Zinc Smelters	
R	Primary Lead Smelters	
S	Primary Aluminum Reduction Plants	
T	Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants	
U	Phosphate Fertilizer Industry: Superphosphoric Acid Plants	
V	Phosphate Fertilizer Industry: Diammonium Phosphate Plants	
W	Phosphate Fertilizer Industry: Triple Superphosphate Plants	
X	Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities	
Y	Coal Preparation Plants	X
Z	Ferroalloy Production Facilities	
AA	Steel Plants: Electric Arc Furnaces Constructed After October 21, 1974 and On or Before August 17, 1983	X
AAa	Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After August 7, 1983	X
BB	Kraft pulp Mills	
CC	Glass Manufacturing Plants	
DD	Grain Elevators	
EE	Surface Coating of Metal Furniture	
FF	(Reserved)	
GG	Stationary Gas Turbines	X
HH	Lime Manufacturing Plants	
KK	Lead-Acid Battery Manufacturing Plants	
LL	Metallic Mineral Processing Plants	
MM	Automobile and Light Duty Trucks Surface Coating Operations	
NN	Phosphate Rock Plants	

Delegation Status for New Source Performance Standards for Hawaii

	Subpart	Hawaii
PP	Ammonium Sulfate Manufacture	
QQ	Graphic Arts Industry: Publication Rotogravure Printing	
RR	Pressure Sensitive Tape and Label Surface Coating Operations	
SS	Industrial Surface Coating: Large Appliances	
TT	Metal Coil Surface Coating	
UU	Asphalt Processing and Asphalt Roofing Manufacture	
VV	Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry	X
VVa	Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006	
WW	Beverage Can Surface Coating Industry	X
XX	Bulk Gasoline Terminals	X
AAA	New Residential Wool Heaters	
BBB	Rubber Tire Manufacturing Industry	
CCC	(Reserved)	
DDD	Volatile Organic Compounds (VOC) Emissions from the Polymer Manufacturing Industry	
EEE	(Reserved)	
FFF	Flexible Vinyl and Urethane Coating and Printing	
GGG	Equipment Leaks of VOC in Petroleum Refineries	X
GGGa	Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006	
HHH	Synthetic Fiber Production Facilities	
III	Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes	
JJJ	Petroleum Dry Cleaners	X
KKK	Equipment Leaks of VOC From Onshore Natural Gas Processing Plants	
LLL	Onshore Natural Gas Processing: SO ₂ Emissions	
MMM	(Reserved)	

Delegation Status for New Source Performance Standards for Hawaii

	Subpart	Hawaii
NNN	Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations	X
OOO	Nonmetallic Mineral Processing Plants	X
PPP	Wool Fiberglass Insulation Manufacturing Plants	
QQQ	VOC Emissions From Petroleum Refinery Wastewater	X
RRR	Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes	
SSS	Magnetic Tape Coating Facilities	
TTT	Industrial Surface Coating: Surface Coating of Plastic Parts for Business Machines	
UUU	Calciners and Dryers in Mineral Industries	X
VVV	Polymeric Coating of Supporting Substrates Facilities	X
WWW	Municipal Solid Waste Landfills	X
AAAA	Small Municipal Waste Combustion Units for Which Construction is Commenced After August 30, 1999 or for Which Modification or Reconstruction is Commenced After June 6, 2001	X
CCCC	Commercial and Industrial Solid Waste Incineration Units for Which Construction Is Commenced After November 30, 1999 or for Which Modification or Reconstruction Is Commenced on or After June 1, 2001	X
EEEE	Other Solid Waste Incineration Units for Which Construction is Commenced After December 9, 2004, or for Which Modification or Reconstruction is Commenced on or After June 16, 2006	
GGGG	(Reserved)	
IIII	Stationary Compression Ignition Internal Combustion Engines	
JJJJ	Stationary Spark Ignition Internal Combustion Engines	
KKKK	Stationary Combustion Turbines	

(4) *Nevada*. The following table identifies delegations for Nevada:

Table 12 to Paragraph (d)(4)—Delegation Status for New Source Performance Standards for Nevada

	Subpart	Air pollution control agency		
		Nevada DEP	Clark County	Washoe County
A	General Provisions	X	X	X

Table 12 to Paragraph (d)(4)—Delegation Status for New Source Performance Standards for Nevada

	Subpart	Air pollution control agency		
		Nevada DEP	Clark County	Washoe County
Cf	Emission Guidelines and Compliance Times for Municipal Solid Waste Landfills	X		
D	Fossil-Fuel Fired Steam Generators Constructed After August 17, 1971	X	X	X
Da	Electric Utility Steam Generating Units Constructed After September 18, 1978	X	X	
Db	Industrial-Commercial-Institutional Steam Generating Units	X	X	
Dc	Small Industrial-Commercial-Institutional Steam Generating Units	X	X	
E	Incinerators	X	X	X
Ea	Municipal Waste Combustors Constructed After December 20, 1989 and On or Before September 20, 1994	X	X	
Eb	Large Municipal Waste Combustors Constructed After September 20, 1994	X	X	
Ec	Hospital/Medical/Infectious Waste Incinerators for Which Construction is Commenced After June 20, 1996	X	X	
F	Portland Cement Plants	X	X	X
G	Nitric Acid Plants	X	X	
Ga	Nitric Acid Plants For Which Construction, Reconstruction or Modification Commenced After October 14, 2011	X		
H	Sulfuric Acid Plant	X	X	
I	Hot Mix Asphalt Facilities	X	X	X
J	Petroleum Refineries	X	X	
Ja	Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007	X		
K	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978	X	X	X
Ka	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984	X	X	X
Kb	Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984	X	X	

Table 12 to Paragraph (d)(4)—Delegation Status for New Source Performance Standards for Nevada

	Subpart	Air pollution control agency		
		Nevada DEP	Clark County	Washoe County
L	Secondary Lead Smelters	X	X	X
M	Secondary Brass and Bronze Production Plants	X	X	
N	Primary Emissions from Basic Oxygen Process Furnaces for Which Construction is Commenced After June 11, 1973	X	X	
Na	Secondary Emissions from Basic Oxygen Process Steelmaking Facilities for Which Construction is Commenced After January 20, 1983	X	X	
O	Sewage Treatment Plants	X	X	X
P	Primary Copper Smelters	X	X	X
Q	Primary Zinc Smelters	X	X	X
R	Primary Lead Smelters	X	X	X
S	Primary Aluminum Reduction Plants	X	X	
T	Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants		X	
U	Phosphate Fertilizer Industry: Superphosphoric Acid Plants		X	
V	Phosphate Fertilizer Industry: Diammonium Phosphate Plants		X	
W	Phosphate Fertilizer Industry: Triple Superphosphate Plants		X	
X	Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities		X	
Y	Coal Preparation and Processing Plants	X	X	X
Z	Ferroalloy Production Facilities	X	X	
AA	Steel Plants: Electric Arc Furnaces Constructed After October 21, 1974 and On or Before August 17, 1983	X	X	
AAa	Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After August 7, 1983	X	X	
BB	Kraft Pulp Mills		X	
CC	Glass Manufacturing Plants	X	X	
DD	Grain Elevators	X	X	X

Table 12 to Paragraph (d)(4)—Delegation Status for New Source Performance Standards for Nevada

	Subpart	Air pollution control agency		
		Nevada DEP	Clark County	Washoe County
EE	Surface Coating of Metal Furniture	X	X	X
FF	(Reserved)			
GG	Stationary Gas Turbines	X	X	X
HH	Lime Manufacturing Plants	X	X	X
KK	Lead-Acid Battery Manufacturing Plants	X	X	X
LL	Metallic Mineral Processing Plants	X	X	X
MM	Automobile and Light Duty Trucks Surface Coating Operations	X	X	X
NN	Phosphate Rock Plants	X	X	X
PP	Ammonium Sulfate Manufacture	X	X	
QQ	Graphic Arts Industry: Publication Rotogravure Printing	X	X	X
RR	Pressure Sensitive Tape and Label Surface Coating Operations	X	X	
SS	Industrial Surface Coating: Large Appliances	X	X	X
TT	Metal Coil Surface Coating	X	X	X
UU	Asphalt Processing and Asphalt Roofing Manufacture	X	X	X
VV	Equipment Leaks of VOC in the Synthetic Organic Industry Chemicals Manufacturing	X	X	X
VVa	Equipment Leaks of VOC in the Synthetic Organic Industry for Which Construction, Reconstruction, or Chemicals Manufacturing Modification Commenced After November 7, 2006	X	X	
WW	Beverage Can Surface Coating Industry	X	X	
XX	Bulk Gasoline Terminals	X	X	
AAA	New Residential Wood Heaters		X	
BBB	Rubber Tire Manufacturing Industry	X	X	
CCC	(Reserved)			
DDD	Volatile Organic Compounds (VOC) Emissions from the Polymer Manufacturing Industry	X	X	

Table 12 to Paragraph (d)(4)—Delegation Status for New Source Performance Standards for Nevada

	Subpart	Air pollution control agency		
		Nevada DEP	Clark County	Washoe County
EEE	(Reserved)			
FFF	Flexible Vinyl and Urethane Coating and Printing	X	X	
GGG	Equipment Leaks of VOC in Petroleum Refineries	X	X	
GGGa	Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006	X	X	
HHH	Synthetic Fiber Production Facilities	X	X	
III	Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes	X	X	
JJJ	Petroleum Dry Cleaners	X	X	X
KKK	Equipment Leaks of VOC From Onshore Natural Gas Processing Plants	X	X	
LLL	Onshore Natural Gas Processing: SO ₂ Emissions	X	X	
MMM	(Reserved)			
NNN	Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations	X	X	
OOO	Nonmetallic Mineral Processing Plants	X	X	
PPP	Wool Fiberglass Insulation Manufacturing Plants	X	X	
QQQ	VOC Emissions From Petroleum Refinery Wastewater Systems	X	X	
RRR	Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes	X	X	
SSS	Magnetic Tape Coating Facilities	X	X	
TTT	Industrial Surface Coating: Surface Coating of Plastic Parts for Business Machines	X	X	X
UUU	Calciners and Dryers in Mineral Industries	X	X	X
VVV	Polymeric Coating of Supporting Substrates Facilities	X	X	X
WWW	Municipal Solid Waste Landfills	X	X	X
XXX	Municipal Solid Waste Landfills that Commenced Construction, Reconstruction, or Modification after July 17, 2014	X		

Table 12 to Paragraph (d)(4)—Delegation Status for New Source Performance Standards for Nevada

	Subpart	Air pollution control agency		
		Nevada DEP	Clark County	Washoe County
AAAA	Small Municipal Waste Combustion Units for Which Construction is Commenced After August 30, 1999 or for Which Modification or Reconstruction is Commenced After June 6, 2001	X	X	X
CCCC	Commercial and Industrial Solid Waste Incineration Units for Which Construction Is Commenced After November 30, 1999 or for Which Modification or Reconstruction Is Commenced on or After June 1, 2001	X	X	X
EEEE	Other Solid Waste Incineration Units for Which Construction is Commenced After December 9, 2004, or for Which Modification or Reconstruction is Commenced on or After June 16, 2006	X	X	X
GGGG	(Reserved)			
HHHH	(Reserved)			
IIII	Stationary Compression Ignition Internal Combustion Engines	X	X	X
JJJJ	Stationary Spark Ignition Internal Combustion Engines	X	X	X
KKKK	Stationary Combustion Turbines	X	X	X
LLLL	New Sewage Sludge Incineration Units		X	
OOOO	Crude Oil and Natural Gas Production, Transmission, and Distribution	X		

(5) *Guam*. The following table identifies delegations as of June 15, 2001:

Delegation Status for New Source Performance Standards for Guam

	Subpart	Guam
A	General Provisions	X
D	Fossil-Fuel Fired Steam Generators Constructed After August 17, 1971	X
Da	Electric Utility Steam Generating Units Constructed After September 18, 1978	
Db	Industrial-Commercial-Institutional Steam Generating Units	
Dc	Small Industrial Steam Generating Units	
E	Incinerators	
Ea	Municipal Waste Combustors Constructed After December 20, 1989 and On or Before September 20, 1994	

Delegation Status for New Source Performance Standards for Guam		
	Subpart	Guam
Eb	Municipal Waste Combustors Constructed After September 20, 1994	
Ec	Hospital/Medical/Infectious Waste Incinerators for Which Construction is Commenced After June 20, 1996	
F	Portland Cement Plants	X
G	Nitric Acid Plants	
H	Sulfuric Acid Plants	
I	Hot Mix Asphalt Facilities	X
J	Petroleum Refineries	X
K	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978	X

(e) The following lists the specific part 60 standards that have been delegated unchanged to the air pollution control agencies in Region 6.

(1) *New Mexico*. The New Mexico Environment Department has been delegated all part 60 standards promulgated by the EPA, except subpart AAA—Standards of Performance for New Residential Wood Heaters; and subpart QQQQ—Standards of Performance for New Residential Hydronic Heaters and Forced-Air Furnaces, as amended in the Federal Register through January 15, 2017.

(2) *Louisiana*. The Louisiana Department of Environmental Quality has been delegated the following part 60 standards promulgated by EPA, as amended in the Federal Register through July 1, 2021. The (X) symbol is used to indicate each subpart that has been delegated.

Delegation Status for Part 60 Standards—State of Louisiana [Excluding Indian Country]		
Subpart	Source category	LDEQ
A	General Provisions	X
Cb	Emissions Guidelines and Compliance Times for Large Municipal Waste Combustors That are Constructed on or Before September 20, 1994	X
Cc	Emission Guidelines and Compliance Times for Municipal Solid Waste Landfills	X
Cd	Emissions Guidelines and Compliance Times for Sulfuric Acid Production Units	X
Ce	Emission Guidelines and Compliance Times for Hospital/Medical/Infectious Waste Incinerators	X
Cf	Emission Guidelines and Compliance Times for Municipal Solid Waste Landfills	X
D	Fossil Fueled Steam Generators	X

Delegation Status for Part 60 Standards—State of Louisiana [Excluding Indian Country]		
Subpart	Source category	LDEQ
Da	Electric Utility Steam Generating Units	X
Db	Industrial-Commercial-Institutional Steam Generating Units	X
Dc	Small Industrial-Commercial-Institutional Steam Generating Units	X
E	Incinerators	X
Ea	Municipal Waste Combustors for Which Construction is Commenced After December 20, 1989, and On or Before September 20, 1994	X
Eb	Large Municipal Waste Combustors for Which Construction is Commenced After September 20, 1994 or for Which Modification or Reconstruction is Commenced After June 19, 1996	X
Ec	Hospital/Medical/Infectious Waste Incinerators	X
F	Portland Cement Plants	X
G	Nitric Acid Plants	X
Ga	Nitric Acid Plants for Which Construction, Reconstruction, or Modification Commenced After October 14, 2011	X
H	Sulfuric Acid Plants	X
I	Hot Mix Asphalt Facilities	X
J	Petroleum Refineries	X
Ja	Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007	X
K	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978	X
Ka	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984	X
Kb	VOC Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984, and On or Before October 4, 2023	X
Kc	VOC Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, October 4, 2023	No
L	Secondary Lead Smelters for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and On or Before December 1,	X

Delegation Status for Part 60 Standards—State of Louisiana [Excluding Indian Country]		
Subpart	Source category	LDEQ
	2022	
La	Secondary Lead Smelters for Which Construction, Reconstruction, or Modification Commenced After December 1, 2022	No
M	Secondary Brass and Bronze Production Plants	X
N	Primary Emissions from Basic Oxygen Process Furnaces for Which Construction Commenced After June 11, 1973	X
Na	Secondary Emissions from Basic Oxygen Process Steelmaking Facilities for Which Construction is Commenced After January 20, 1983	X
O	Sewage Treatment Plants	X
P	Primary Copper Smelters	X
Q	Primary Zinc Smelters	X
R	Primary Lead Smelters	X
S	Primary Aluminum Reduction Plants	X
T	Phosphate Fertilizer Industry: Wet Process Phosphoric Plants	X
U	Phosphate Fertilizer Industry: Superphosphoric Acid Plants	X
V	Phosphate Fertilizer Industry: Diammonium Phosphate Plants	X
W	Phosphate Fertilizer Industry: Triple Superphosphate Plants	X
X	Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities	X
Y	Coal Preparation and Processing Plants	X
Z	Ferroalloy Production Facilities	X
AA	Steel Plants: Electric Arc Furnaces Constructed After October 21, 1974, and On or Before August 17, 1983	X
AAa	Steel Plants: Electric Arc Furnaces & Argon-Oxygen Decarburization Vessels Constructed After August 17, 1983, and On or Before May 16, 2022	X
AAb	Steel Plants: Electric Arc Furnaces & Argon-Oxygen Decarburization Vessels Constructed After May 16, 2022	No
BB	Kraft Pulp Mills	X
BBa	Kraft Pulp Mill Affected Sources for Which Construction, Reconstruction, or	X

Permit Issued: [month day, year]

Permit Expires: [month day, year]

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Delegation Status for Part 60 Standards—State of Louisiana [Excluding Indian Country]		
Subpart	Source category	LDEQ
	Modification Commenced After May 23, 2013	
CC	Glass Manufacturing Plants	X
DD	Grain Elevators	X
EE	Surface Coating of Metal Furniture	X
GG	Stationary Gas Turbines	X
HH	Lime Manufacturing Plants	X
KK	Lead-Acid Battery Manufacturing Plants for Which Construction, Reconstruction, or Modification Commenced After January 14, 1980, and On or Before February 23, 2022	X
KKa	Lead-Acid Battery Manufacturing Plants for Which Construction, Reconstruction, or Modification Commenced After February 23, 2022	No
LL	Metallic Mineral Processing Plants	X
MM	Automobile & Light Duty Truck Surface Coating Operations for which Construction, Modification or Reconstruction Commenced After October 5, 1979, and On or Before May 18, 2022	X
MMa	Automobile & Light Duty Truck Surface Coating Operations for which Construction, Modification or Reconstruction Commenced After May 18, 2022	No
NN	Phosphate Manufacturing Plants	X
PP	Ammonium Sulfate Manufacture	X
QQ	Graphic Arts Industry: Publication Rotogravure Printing	X
RR	Pressure Sensitive Tape and Label Surface Coating Operations	X
SS	Industrial Surface Coating: Large Appliances	X
TT	Metal Coil Surface Coating	X
UU	Asphalt Processing and Asphalt Roofing Manufacture	X
VV	Equipment Leaks of VOC in the SOCM I Industry for Which Construction, Reconstruction, or Modification Commenced After January 5, 1981, and on or Before November 7, 2006	X
VVa	Equipment Leaks of VOC in the SOCM I Industry for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006, and on	X

Delegation Status for Part 60 Standards—State of Louisiana [Excluding Indian Country]		
Subpart	Source category	LDEQ
	or Before April 25, 2023	
VVb	Equipment Leaks of VOC in the SOCMI Industry for Which Construction, Reconstruction, or Modification Commenced After April 25, 2023	No
WW	Beverage Can Surface Coating Industry	X
XX	Bulk Gasoline Terminals That Commenced Construction, Modification, or Reconstruction After December 17, 1980, and On or Before June 10, 2022	X
XXa	Bulk Gasoline Terminals That Commenced Construction, Modification, or Reconstruction After June 10, 2022	No
AAA	New Residential Wood Heaters	No
BBB	Rubber Tire Manufacturing Industry	X
CCC	[Reserved]	
DDD	Volatile Organic Compound (VOC) Emissions from the Polymer Manufacturing Industry	X
EEE	[Reserved]	
FFF	Flexible Vinyl and Urethane Coating and Printing	X
GGG	Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After January 4, 1983, and On or Before November 7, 2006	X
GGGa	Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006	X
HHH	Synthetic Fiber Production	X
III	VOC Emissions from the SOCMI Air Oxidation Unit Processes	X
IIIa	VOC Emissions from the SOCMI Air Oxidation Unit Processes for Which Construction, Reconstruction, or Modification Commenced After April 25, 2023	No
JJJ	Petroleum Dry Cleaners	X
KKK	VOC Equipment Leaks From Onshore Natural Gas Processing Plants	X
LLL	Onshore Natural Gas Processing: SO ₂ Emissions	X
MMM	[Reserved]	

Delegation Status for Part 60 Standards—State of Louisiana [Excluding Indian Country]		
Subpart	Source category	LDEQ
NNN	VOC Emissions from SOCM I Distillation Operations	X
NNNa	VOC Emissions from SOCM I Distillation Operations for Which Construction, Reconstruction, or Modification Commenced After April 25, 2023	No
OOO	Nonmetallic Mineral Processing Plants	X
PPP	Wool Fiberglass Insulation Manufacturing Plants	X
QQQ	VOC Emissions From Petroleum Refinery Wastewater Systems	X
RRR	VOC Emissions from SOCM I Reactor Processes	X
RRRa	VOC Emissions from SOCM I Reactor Processes for Which Construction, Reconstruction, or Modification Commenced After April 25, 2023	No
SSS	Magnetic Tape Coating Operations	X
TTT	Industrial Surface Coating: Plastic Parts for Business Machines	X
TTTa	Industrial Surface Coating: Surface Coating of Plastic Parts for Business Machines for Which Construction, Reconstruction, or Modification Commenced After June 21, 2022	No
UUU	Calciners and Dryers in Mineral Industries	X
VVV	Polymeric Coating of Supporting Substrates Facilities	X
WWW	Municipal Solid Waste Landfills	X
XXX	Municipal Solid Waste Landfills That Commenced Construction, Reconstruction, or Modification After July 17, 2014	X
YYY-ZZZ	[Reserved]	
AAAA	Small Municipal Waste Combustion Units (Construction is Commenced After 8/30/99 or Modification/Reconstruction is Commenced After 6/06/2001)	X
BBBB	Emission Guidelines and Compliance Times for Small Municipal Waste Combustion Units Constructed on or Before August 30, 1999	X
CCCC	Commercial & Industrial Solid Waste Incineration Units (Construction is Commenced After 11/30/1999 or Modification/Reconstruction is Commenced on or After 6/01/2001)	X
DDDD	Emission Guidelines & Compliance Times for Commercial & Industrial Solid Waste Incineration Units (Commenced Construction On or Before 11/30/1999)	X

Delegation Status for Part 60 Standards—State of Louisiana [Excluding Indian Country]		
Subpart	Source category	LDEQ
EEEE	Other Solid Waste Incineration Units (Constructed after 12/09/2004 or Modification/Reconstruction is commenced on or after 06/16/2004)	X
FFFF	Emission Guidelines and Compliance Times for Other Solid Waste Incineration Units that Commenced Construction On or Before December 9, 2004	X
GGG- HHH	[Reserved]	
IIII	Stationary Compression Ignition Internal Combustion Engines	X
JJJJ	Stationary Spark Ignition Internal Combustion Engines	X
KKKK	Stationary Combustion Turbines (Construction Commenced After 02/18/2005)	X
LLLL	New Sewage Sludge Incineration Units	X
MMMM	Emission Guidelines and Compliance Times for Existing Sewage Sludge Incineration Units	X
NNNN	[Reserved]	
OOOO	Crude Oil and Natural Gas Production, Transmission and Distribution	X
OOOOa	Crude Oil and Natural Gas Facilities for Which Construction, Modification or Reconstruction Commenced After September 18, 2015 and On or Before December 6, 2022	X
OOOOb	Crude Oil and Natural Gas Facilities for Which Construction, Modification or Reconstruction Commenced After December 6, 2022	No
OOOOc	Emissions Guidelines for Greenhouse Gas Emissions from Existing Crude Oil and Natural Gas Facilities	No
PPPP	[Reserved]	
QQQQ	New Residential Hydronic Heaters and Forced-Air Furnaces	X
TTTT	Greenhouse Gas Emissions for Electric Generating Units	X
TTTTa	Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units	No
UUUUa	[Reserved]	
UUUUb	Greenhouse Gas Emissions for Electric Utility Generating Units	No

(3) *Albuquerque-Bernalillo County Air Quality Control Board*. The Albuquerque-Bernalillo County Air Quality Control Board has been delegated all part 60 standards promulgated by the EPA, except subpart AAA of this part and subpart QQQQ of this part as amended through January 23, 2017.

Editorial Note: For Federal Register citations affecting § 60.4, see the List of CFR Sections Affected, which appears in the Finding Aids section of the printed volume and at www.govinfo.gov.

§ 60.5 Determination of construction or modification.

- (a) When requested to do so by an owner or operator, the Administrator will make a determination of whether action taken or intended to be taken by such owner or operator constitutes construction (including reconstruction) or modification or the commencement thereof within the meaning of this part.
- (b) The Administrator will respond to any request for a determination under paragraph (a) of this section within 30 days of receipt of such request.

§ 60.6 Review of plans.

- (a) When requested to do so by an owner or operator, the Administrator will review plans for construction or modification for the purpose of providing technical advice to the owner or operator.
- (b)
 - (1) A separate request shall be submitted for each construction or modification project.
 - (2) Each request shall identify the location of such project, and be accompanied by technical information describing the proposed nature, size, design, and method of operation of each affected facility involved in such project, including information on any equipment to be used for measurement or control of emissions.
- (c) Neither a request for plans review nor advice furnished by the Administrator in response to such request shall
 - (1) relieve an owner or operator of legal responsibility for compliance with any provision of this part or of any applicable State or local requirement, or
 - (2) prevent the Administrator from implementing or enforcing any provision of this part or taking any other action authorized by the Act.

§ 60.7 Notification and record keeping.

- (a) Any owner or operator subject to the provisions of this part shall furnish the Administrator written notification or, if acceptable to both the Administrator and the owner or operator of a source, electronic notification, as follows:
 - (1) A notification of the date construction (or reconstruction as defined under § 60.15) of an affected facility is commenced postmarked no later than 30 days after such date. This requirement shall not apply in the case of mass-produced facilities which are purchased in completed form.
 - (2) [Reserved]
 - (3) A notification of the actual date of initial startup of an affected facility postmarked within 15 days after such date.
 - (4) A notification of any physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applies, unless that change is specifically exempted under an applicable subpart or in § 60.14(e). This notice shall be postmarked 60 days or as soon as practicable before the change is commenced and shall include information describing the precise nature of the change, present and proposed emission control systems, productive capacity of the facility before and after the change, and the

expected completion date of the change. The Administrator may request additional relevant information subsequent to this notice.

(5) A notification of the date upon which demonstration of the continuous monitoring system performance commences in accordance with § 60.13(c). Notification shall be postmarked not less than 30 days prior to such date.

(6) A notification of the anticipated date for conducting the opacity observations required by § 60.11(e)(1) of this part. The notification shall also include, if appropriate, a request for the Administrator to provide a visible emissions reader during a performance test. The notification shall be postmarked not less than 30 days prior to such date.

(7) A notification that continuous opacity monitoring system data results will be used to determine compliance with the applicable opacity standard during a performance test required by § 60.8 in lieu of Method 9 observation data as allowed by § 60.11(e)(5) of this part. This notification shall be postmarked not less than 30 days prior to the date of the performance test.

(b) Any owner or operator subject to the provisions of this part shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative.

(c) Each owner or operator required to install a continuous monitoring device shall submit excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and/or summary report form (see paragraph (d) of this section) to the Administrator semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each six-month period. Written reports of excess emissions shall include the following information:

(1) The magnitude of excess emissions computed in accordance with § 60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period.

(2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted.

(3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.

(4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.

(d) The summary report form shall contain the information and be in the format shown in figure 1 unless otherwise specified by the Administrator. One summary report form shall be submitted for each pollutant monitored at each affected facility.

(1) If the total duration of excess emissions for the reporting period is less than 1 percent of the total operating time for the reporting period and CMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report form shall be submitted and the excess emission report described in § 60.7(c) need not be submitted unless requested by the Administrator.

(2) If the total duration of excess emissions for the reporting period is 1 percent or greater of the total operating time for the reporting period or the total CMS downtime for the reporting period is 5 percent or greater of the total operating time for the reporting period, the summary report form and the excess emission report described in § 60.7(c) shall both be submitted.

Figure 1—Summary Report—Gaseous and Opacity Excess Emission and Monitoring System Performance

Pollutant (Circle One—SO₂/NO_x/TRS/H₂S/CO/Opacity)

Reporting period dates: From _____ to _____

Company:

Emission Limitation

Address:

Monitor Manufacturer and Model No.

Date of Latest CMS Certification or Audit

Process Unit(s) Description:

Total source operating time in reporting period¹

Emission data summary ¹		CMS performance summary ¹	
1. Duration of excess emissions in reporting period due to:		1. CMS downtime in reporting period due to:	
a. Startup/shutdown		a. Monitor equipment malfunctions	
b. Control equipment problems		b. Non-Monitor equipment malfunctions	
c. Process problems		c. Quality assurance calibration	
d. Other known causes		d. Other known causes	
e. Unknown causes		e. Unknown causes	
2. Total duration of excess emission		2. Total CMS Downtime	
3. Total duration of excess emissions × (100) [Total source operating time]	% ²	3. [Total CMS Downtime] × (100) [Total source operating time]	% ²

¹ For opacity, record all times in minutes. For gases, record all times in hours.

² For the reporting period: If the total duration of excess emissions is 1 percent or greater of the total operating time or the total CMS downtime is 5 percent or greater of the total operating time, both the summary report form and the excess emission report described in § 60.7(c) shall be submitted.

On a separate page, describe any changes since last quarter in CMS, process or controls. I certify that the information contained in this report is true, accurate, and complete.

Name

Signature

Title

Date

(e)

(1) Notwithstanding the frequency of reporting requirements specified in paragraph (c) of this section, an owner or operator who is required by an applicable subpart to submit excess emissions and monitoring systems performance reports (and summary reports) on a quarterly (or more frequent) basis may reduce the frequency of reporting for that standard to semiannual if the following conditions are met:

(i) For 1 full year (e.g., 4 quarterly or 12 monthly reporting periods) the affected facility's excess emissions and monitoring systems reports submitted to comply with a standard under this part continually demonstrate that the facility is in compliance with the applicable standard;

(ii) The owner or operator continues to comply with all recordkeeping and monitoring requirements specified in this subpart and the applicable standard; and

(iii) The Administrator does not object to a reduced frequency of reporting for the affected facility, as provided in paragraph (e)(2) of this section.

(2) The frequency of reporting of excess emissions and monitoring systems performance (and summary) reports may be reduced only after the owner or operator notifies the Administrator in writing of his or her intention to make such a change and the Administrator does not object to the intended change. In deciding whether to approve a reduced frequency of reporting, the Administrator may review information concerning the source's entire previous performance history during the required recordkeeping period prior to the intended change, including performance test results, monitoring data, and evaluations of an owner or operator's conformance with operation and maintenance requirements. Such information may be used by the Administrator to make a judgment about the source's potential for noncompliance in the future. If the Administrator disapproves the owner or operator's request to reduce the frequency of reporting, the Administrator will notify the owner or operator in writing within 45 days after receiving notice of the owner or operator's intention. The notification from the Administrator to the owner or operator will specify the grounds on which the disapproval is based. In the absence of a notice of disapproval within 45 days, approval is automatically granted.

(3) As soon as monitoring data indicate that the affected facility is not in compliance with any emission limitation or operating parameter specified in the applicable standard, the frequency of reporting shall revert to the frequency specified in the applicable standard, and the owner or operator shall submit an excess emissions and monitoring systems performance report (and summary report, if required) at the next appropriate reporting period following the noncomplying event. After demonstrating compliance with the applicable standard for another full year, the owner or operator may again request approval from the Administrator to reduce the frequency of reporting for that standard as provided for in paragraphs (e)(1) and (e)(2) of this section.

(f) Any owner or operator subject to the provisions of this part shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this part recorded in a permanent form suitable for inspection. The file shall be retained for at least two years following the date of such measurements, maintenance, reports, and records, except as follows:

(1) This paragraph applies to owners or operators required to install a continuous emissions monitoring system (CEMS) where the CEMS installed is automated, and where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. An automated CEMS records and reduces the measured data to the form of the pollutant emission standard through the use of a computerized data acquisition system. In lieu of maintaining a file of all CEMS subhourly measurements as required under paragraph (f) of this section, the owner or operator shall retain the most recent consecutive three averaging periods of subhourly measurements

and a file that contains a hard copy of the data acquisition system algorithm used to reduce the measured data into the reportable form of the standard.

(2) This paragraph applies to owners or operators required to install a CEMS where the measured data is manually reduced to obtain the reportable form of the standard, and where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. In lieu of maintaining a file of all CEMS subhourly measurements as required under paragraph (f) of this section, the owner or operator shall retain all subhourly measurements for the most recent reporting period. The subhourly measurements shall be retained for 120 days from the date of the most recent summary or excess emission report submitted to the Administrator.

(3) The Administrator or delegated authority, upon notification to the source, may require the owner or operator to maintain all measurements as required by paragraph (f) of this section, if the Administrator or the delegated authority determines these records are required to more accurately assess the compliance status of the affected source.

(g) If notification substantially similar to that in paragraph (a) of this section is required by any other State or local agency, sending the Administrator a copy of that notification will satisfy the requirements of paragraph (a) of this section.

(h) Individual subparts of this part may include specific provisions which clarify or make inapplicable the provisions set forth in this section.

§ 60.8 Performance tests.

(a) Except as specified in paragraphs (a)(1), (a)(2), (a)(3), and (a)(4) of this section, within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility, or at such other times specified by this part, and at such other times as may be required by the Administrator under section 114 of the Act, the owner or operator of such facility shall conduct performance test(s) and furnish the Administrator a written report of the results of such performance test(s).

(1) If a force majeure is about to occur, occurs, or has occurred for which the affected owner or operator intends to assert a claim of force majeure, the owner or operator shall notify the Administrator, in writing as soon as practicable following the date the owner or operator first knew, or through due diligence should have known that the event may cause or caused a delay in testing beyond the regulatory deadline, but the notification must occur before the performance test deadline unless the initial force majeure or a subsequent force majeure event delays the notice, and in such cases, the notification shall occur as soon as practicable.

(2) The owner or operator shall provide to the Administrator a written description of the force majeure event and a rationale for attributing the delay in testing beyond the regulatory deadline to the force majeure; describe the measures taken or to be taken to minimize the delay; and identify a date by which the owner or operator proposes to conduct the performance test. The performance test shall be conducted as soon as practicable after the force majeure occurs.

(3) The decision as to whether or not to grant an extension to the performance test deadline is solely within the discretion of the Administrator. The Administrator will notify the owner or operator in writing of approval or disapproval of the request for an extension as soon as practicable.

(4) Until an extension of the performance test deadline has been approved by the Administrator under paragraphs (a)(1), (2), and (3) of this section, the owner or operator of the affected facility remains strictly subject to the requirements of this part.

(b) Performance tests shall be conducted and data reduced in accordance with the test methods and procedures contained in each applicable subpart unless the Administrator

- (1) specifies or approves, in specific cases, the use of a reference method with minor changes in methodology,
- (2) approves the use of an equivalent method,
- (3) approves the use of an alternative method the results of which he has determined to be adequate for indicating whether a specific source is in compliance,
- (4) waives the requirement for performance tests because the owner or operator of a source has demonstrated by other means to the Administrator's satisfaction that the affected facility is in compliance with the standard, or
- (5) approves shorter sampling times and smaller sample volumes when necessitated by process variables or other factors. Nothing in this paragraph shall be construed to abrogate the Administrator's authority to require testing under section 114 of the Act.

(c) 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 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.

(d) The owner or operator of an affected facility shall provide the Administrator at least 30 days prior notice of any performance test, except as specified under other subparts, to afford the Administrator the opportunity to have an observer present. If after 30 days notice for an initially scheduled performance test, there is a delay (due to operational problems, etc.) in conducting the scheduled performance test, the owner or operator of an affected facility shall notify the Administrator (or delegated State or local agency) as soon as possible of any delay in the original test date, either by providing at least 7 days prior notice of the rescheduled date of the performance test, or by arranging a rescheduled date with the Administrator (or delegated State or local agency) by mutual agreement.

(e) The owner or operator of an affected facility shall provide, or cause to be provided, performance testing facilities as follows:

- (1) Sampling ports adequate for test methods applicable to such facility. This includes
 - (i) constructing the air pollution control system such that volumetric flow rates and pollutant emission rates can be accurately determined by applicable test methods and procedures and
 - (ii) providing a stack or duct free of cyclonic flow during performance tests, as demonstrated by applicable test methods and procedures.
- (2) Safe sampling platform(s).
- (3) Safe access to sampling platform(s).
- (4) Utilities for sampling and testing equipment.

(f) Unless otherwise specified in the applicable subpart, each performance test shall consist of three separate runs using the applicable test method.

- (1) Each run shall be conducted for the time and under the conditions specified in the applicable standard. For the purpose of determining compliance with an applicable standard, the arithmetic means of results of the three runs shall apply. In the event that a sample is accidentally lost or conditions occur in which one of the three runs must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train,

extreme meteorological conditions, or other circumstances, beyond the owner or operator's control, compliance may, upon the Administrator's approval, be determined using the arithmetic mean of the results of the two other runs.

(2) Contents of report (electronic or paper submitted copy). Unless otherwise specified in a relevant standard or test method, or as otherwise approved by the Administrator in writing, the report for a performance test shall include the elements identified in paragraphs (f)(2)(i) through (vi) of this section.

(i) General identification information for the facility including a mailing address, the physical address, the owner or operator or responsible official (where applicable) and his/her email address, and the appropriate Federal Registry System (FRS) number for the facility.

(ii) Purpose of the test including the applicable regulation(s) requiring the test, the pollutant(s) and other parameters being measured, the applicable emission standard and any process parameter component, and a brief process description.

(iii) Description of the emission unit tested including fuel burned, control devices, and vent characteristics; the appropriate source classification code (SCC); the permitted maximum process rate (where applicable); and the sampling location.

(iv) Description of sampling and analysis procedures used and any modifications to standard procedures, quality assurance procedures and results, record of process operating conditions that demonstrate the applicable test conditions are met, and values for any operating parameters for which limits were being set during the test.

(v) Where a test method requires you record or report, the following shall be included: Record of preparation of standards, record of calibrations, raw data sheets for field sampling, raw data sheets for field and laboratory analyses, chain-of-custody documentation, and example calculations for reported results.

(vi) Identification of the company conducting the performance test including the primary office address, telephone number, and the contact for this test program including his/her email address.

(g) The performance testing shall include a test method performance audit (PA) during the performance test. The PAs consist of blind audit samples supplied by an accredited audit sample provider and analyzed during the performance test in order to provide a measure of test data bias. Gaseous audit samples are designed to audit the performance of the sampling system as well as the analytical system and must be collected by the sampling system during the compliance test just as the compliance samples are collected. If a liquid or solid audit sample is designed to audit the sampling system, it must also be collected by the sampling system during the compliance test. If multiple sampling systems or sampling trains are used during the compliance test for any of the test methods, the tester is only required to use one of the sampling systems per method to collect the audit sample. The audit sample must be analyzed by the same analyst using the same analytical reagents and analytical system and at the same time as the compliance samples. Retests are required when there is a failure to produce acceptable results for an audit sample. However, if the audit results do not affect the compliance or noncompliance status of the affected facility, the compliance authority may waive the reanalysis requirement, further audits, or retests and accept the results of the compliance test. Acceptance of the test results shall constitute a waiver of the reanalysis requirement, further audits, or retests. The compliance authority may also use the audit sample failure and the compliance test results as evidence to determine the compliance or noncompliance status of the affected facility. A blind audit sample is a sample whose value is known only to the sample provider and is not revealed to the tested facility until after they report the measured value of the audit sample. For pollutants that exist in the gas phase at ambient temperature, the audit sample shall consist of an appropriate concentration of the pollutant in air or nitrogen that can be introduced into the sampling system of the test method at or near the same entry point as a

sample from the emission source. If no gas phase audit samples are available, an acceptable alternative is a sample of the pollutant in the same matrix that would be produced when the sample is recovered from the sampling system as required by the test method. For samples that exist only in a liquid or solid form at ambient temperature, the audit sample shall consist of an appropriate concentration of the pollutant in the same matrix that would be produced when the sample is recovered from the sampling system as required by the test method. An accredited audit sample provider (AASP) is an organization that has been accredited to prepare audit samples by an independent, third party accrediting body.

(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.

(2) An AASP shall have and shall prepare, analyze, and report the true value of audit samples in accordance with a written technical criteria document that describes how audit samples will be prepared and distributed in a manner that will ensure the integrity of the audit sample program. An acceptable technical criteria document shall contain standard operating procedures for all of the following operations:

- (i) Preparing the sample;
- (ii) Confirming the true concentration of the sample;
- (iii) Defining the acceptance limits for the results from a well qualified tester. This procedure must use well established statistical methods to analyze historical results from well qualified testers. The

acceptance limits shall be set so that there is 95 percent confidence that 90 percent of well qualified labs will produce future results that are within the acceptance limit range.

(iv) Providing the opportunity for the compliance authority to comment on the selected concentration level for an audit sample;

(v) Distributing the sample to the user in a manner that guarantees that the true value of the sample is unknown to the user;

(vi) Recording the measured concentration reported by the user and determining if the measured value is within acceptable limits;

(vii) The AASP shall report the results from each audit sample in a timely manner to the compliance authority and then to the source owner, operator, or representative. The AASP 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 source owner, operator, or representative. The results shall include the name of the facility tested, the date on which the compliance test was conducted, the name of the company performing the sample collection, the name of the company that analyzed the compliance samples including the audit sample, the measured result for the audit sample, and whether the testing company passed or failed the audit. The AASP shall report the true value of the audit sample to the compliance authority. The AASP may report the true value to the source owner, operator, or representative if the AASP's operating plan ensures that no laboratory will receive the same audit sample twice.

(viii) Evaluating the acceptance limits of samples at least once every two years to determine in cooperation with the voluntary consensus standard body if they should be changed;

(ix) Maintaining a database, accessible to the compliance authorities, of results from the audit that shall include the name of the facility tested, the date on which the compliance test was conducted, the name of the company performing the sample collection, the name of the company that analyzed the compliance samples including the audit sample, the measured result for the audit sample, the true value of the audit sample, the acceptance range for the measured value, and whether the testing company passed or failed the audit.

(3) The accrediting body shall have a written technical criteria document that describes how it will ensure that the AASP is operating in accordance with the AASP technical criteria document that describes how audit samples are to be prepared and distributed. This document shall contain standard operating procedures for all of the following operations:

(i) Checking audit samples to confirm their true value as reported by the AASP;

(ii) Performing technical systems audits of the AASP's facilities and operating procedures at least once every two years;

(iii) Providing standards for use by the voluntary consensus standard body to approve the accrediting body that will accredit the audit sample providers.

(4) The technical criteria documents for the accredited sample providers and the accrediting body shall be developed through a public process guided by a voluntary consensus standards body (VCSB). The VCSB shall operate in accordance with the procedures and requirements in the Office of Management and Budget Circular A-119. A copy of Circular A-119 is available upon request by writing the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW., Washington, DC 20503, by calling (202) 395-6880 or downloading online at http://standards.gov/standards__gov/a119.cfm. The VCSB shall approve all accrediting bodies. The Administrator will review all technical criteria documents. If the technical criteria documents do not meet the minimum technical requirements in paragraphs (g)(2) through (4) of this section, the

technical criteria documents are not acceptable and the proposed audit sample program is not capable of producing audit samples of sufficient quality to be used in a compliance test. All acceptable technical criteria documents shall be posted on the EPA Web site at the following URL, <http://www.epa.gov/ttn/emc>.

(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.

§ 60.9 Availability of information.

The availability to the public of information provided to, or otherwise obtained by, the Administrator under this part shall be governed by part 2 of this chapter. (Information submitted voluntarily to the Administrator for the purposes of §§ 60.5 and 60.6 is governed by §§ 2.201 through 2.213 of this chapter and not by § 2.301 of this chapter.)

§ 60.10 State authority.

The provisions of this part shall not be construed in any manner to preclude any State or political subdivision thereof from:

- (a) Adopting and enforcing any emission standard or limitation applicable to an affected facility, provided that such emission standard or limitation is not less stringent than the standard applicable to such facility.
- (b) Requiring the owner or operator of an affected facility to obtain permits, licenses, or approvals prior to initiating construction, modification, or operation of such facility.

§ 60.11 Compliance with standards and maintenance requirements.

- (a) Compliance with standards in this part, other than opacity standards, shall be determined in accordance with performance tests established by § 60.8, unless otherwise specified in the applicable standard.
- (b) Compliance with opacity standards in this part shall be determined by conducting observations in accordance with Method 9 in appendix A of this part, any alternative method that is approved by the Administrator, or as provided in paragraph (e)(5) of this section. For purposes of determining initial compliance, the minimum total time of observations shall be 3 hours (30 6-minute averages) for the performance test or other set of observations (meaning those fugitive-type emission sources subject only to an opacity standard).
- (c) The opacity standards set forth in this part shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard.
- (d) At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.
- (e)
 - (1) For the purpose of demonstrating initial compliance, opacity observations shall be conducted concurrently with the initial performance test required in § 60.8 unless one of the following conditions apply. If no

performance test under § 60.8 is required, then opacity observations shall 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 of the facility. If visibility or other conditions prevent the opacity observations from being conducted concurrently with the initial performance test required under § 60.8, the source owner or operator shall reschedule the opacity observations as soon after the initial performance test as possible, but not later than 30 days thereafter, and shall advise the Administrator of the rescheduled date. In these cases, the 30-day prior notification to the Administrator required in § 60.7(a)(6) shall be waived. The rescheduled opacity observations shall be conducted (to the extent possible) under the same operating conditions that existed during the initial performance test conducted under § 60.8. The visible emissions observer shall determine whether visibility or other conditions prevent the opacity observations from being made concurrently with the initial performance test in accordance with procedures contained in Method 9 of appendix B of this part. Opacity readings of portions of plumes which contain condensed, uncombined water vapor shall not be used for purposes of determining compliance with opacity standards. The owner or operator of an affected facility shall make available, upon request by the Administrator, such records as may be necessary to determine the conditions under which the visual observations were made and shall provide evidence indicating proof of current visible observer emission certification. Except as provided in paragraph (e)(5) of this section, the results of continuous monitoring by transmissometer which indicate that the opacity at the time visual observations were made was not in excess of the standard are probative but not conclusive evidence of the actual opacity of an emission, provided that the source shall meet the burden of proving that the instrument used meets (at the time of the alleged violation) Performance Specification 1 in appendix B of this part, has been properly maintained and (at the time of the alleged violation) that the resulting data have not been altered in any way.

(2) Except as provided in paragraph (e)(3) of this section, the owner or operator of an affected facility to which an opacity standard in this part applies shall conduct opacity observations in accordance with paragraph (b) of this section, shall record the opacity of emissions, and shall report to the Administrator the opacity results along with the results of the initial performance test required under § 60.8. The inability of an owner or operator to secure a visible emissions observer shall not be considered a reason for not conducting the opacity observations concurrent with the initial performance test.

(3) The owner or operator of an affected facility to which an opacity standard in this part applies may request the Administrator to determine and to record the opacity of emissions from the affected facility during the initial performance test and at such times as may be required. The owner or operator of the affected facility shall report the opacity results. Any request to the Administrator to determine and to record the opacity of emissions from an affected facility shall be included in the notification required in § 60.7(a)(6). If, for some reason, the Administrator cannot determine and record the opacity of emissions from the affected facility during the performance test, then the provisions of paragraph (e)(1) of this section shall apply.

(4) An owner or operator of an affected facility using a continuous opacity monitor (transmissometer) shall record the monitoring data produced during the initial performance test required by § 60.8 and shall furnish the Administrator a written report of the monitoring results along with Method 9 and § 60.8 performance test results.

(5) An owner or operator of an affected facility subject to an opacity standard may submit, for compliance purposes, continuous opacity monitoring system (COMS) data results produced during any performance test required under § 60.8 in lieu of Method 9 observation data. If an owner or operator elects to submit COMS data for compliance with the opacity standard, he shall notify the Administrator of that decision, in writing, at least 30 days before any performance test required under § 60.8 is conducted. Once the owner or operator of an affected facility has notified the Administrator to that effect, the COMS data results will be used to determine opacity compliance during subsequent tests required under § 60.8 until the owner or operator notifies the Administrator, in writing, to the contrary. For the purpose of determining compliance with the opacity standard

during a performance test required under § 60.8 using COMS data, the minimum total time of COMS data collection shall be averages of all 6-minute continuous periods within the duration of the mass emission performance test. Results of the COMS opacity determinations shall be submitted along with the results of the performance test required under § 60.8. The owner or operator of an affected facility using a COMS for compliance purposes is responsible for demonstrating that the COMS meets the requirements specified in § 60.13(c) of this part, that the COMS has been properly maintained and operated, and that the resulting data have not been altered in any way. If COMS data results are submitted for compliance with the opacity standard for a period of time during which Method 9 data indicates noncompliance, the Method 9 data will be used to determine compliance with the opacity standard.

(6) Upon receipt from an owner or operator of the written reports of the results of the performance tests required by § 60.8, the opacity observation results and observer certification required by § 60.11(e)(1), and the COMS results, if applicable, the Administrator will make a finding concerning compliance with opacity and other applicable standards. If COMS data results are used to comply with an opacity standard, only those results are required to be submitted along with the performance test results required by § 60.8. If the Administrator finds that an affected facility is in compliance with all applicable standards for which performance tests are conducted in accordance with § 60.8 of this part but during the time such performance tests are being conducted fails to meet any applicable opacity standard, he shall notify the owner or operator and advise him that he may petition the Administrator within 10 days of receipt of notification to make appropriate adjustment to the opacity standard for the affected facility.

(7) The Administrator will grant such a petition upon a demonstration by the owner or operator that the affected facility and associated air pollution control equipment was operated and maintained in a manner to minimize the opacity of emissions during the performance tests; that the performance tests were performed under the conditions established by the Administrator; and that the affected facility and associated air pollution control equipment were incapable of being adjusted or operated to meet the applicable opacity standard.

(8) The Administrator will establish an opacity standard for the affected facility meeting the above requirements at a level at which the source will be able, as indicated by the performance and opacity tests, to meet the opacity standard at all times during which the source is meeting the mass or concentration emission standard. The Administrator will promulgate the new opacity standard in the Federal Register.

(f) Special provisions set forth under an applicable subpart shall supersede any conflicting provisions in paragraphs (a) through (e) of this section.

(g) For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any standard in this part, nothing in this part shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

§ 60.12 Circumvention.

No owner or operator subject to the provisions of this part shall build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gases discharged to the atmosphere.

§ 60.13 Monitoring requirements.

(a) For the purposes of this section, all continuous monitoring systems required under applicable subparts shall be subject to the provisions of this section upon promulgation of performance specifications for continuous monitoring systems under appendix B to this part and, if the continuous monitoring system is used to demonstrate

compliance with emission limits on a continuous basis, appendix F to this part, unless otherwise specified in an applicable subpart or by the Administrator. Appendix F is applicable December 4, 1987.

(b) All continuous monitoring systems and monitoring devices shall be installed and operational prior to conducting performance tests under § 60.8. Verification of operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device.

(c) If the owner or operator of an affected facility elects to submit continuous opacity monitoring system (COMS) data for compliance with the opacity standard as provided under § 60.11(e)(5), he shall conduct a performance evaluation of the COMS as specified in Performance Specification 1, appendix B, of this part before the performance test required under § 60.8 is conducted. Otherwise, the owner or operator of an affected facility shall conduct a performance evaluation of the COMS or continuous emission monitoring system (CEMS) during any performance test required under § 60.8 or within 30 days thereafter in accordance with the applicable performance specification in appendix B of this part. The owner or operator of an affected facility shall conduct COMS or CEMS performance evaluations at such other times as may be required by the Administrator under section 114 of the Act.

(1) The owner or operator of an affected facility using a COMS to determine opacity compliance during any performance test required under § 60.8 and as described in § 60.11(e)(5) shall furnish the Administrator two or, upon request, more copies of a written report of the results of the COMS performance evaluation described in paragraph (c) of this section at least 10 days before the performance test required under § 60.8 is conducted.

(2) Except as provided in paragraph (c)(1) of this section, the owner or operator of an affected facility shall furnish the Administrator within 60 days of completion two or, upon request, more copies of a written report of the results of the performance evaluation.

(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.

(2) Unless otherwise approved by the Administrator, the following procedures must be followed for a COMS. Minimum procedures must include an automated method for producing a simulated zero opacity condition and an upscale opacity condition using a certified neutral density filter or other related technique to produce a known obstruction of the light beam. Such procedures must provide a system check of all active analyzer internal optics with power or curvature, all active electronic circuitry including the light source and photodetector assembly, and electronic or electro-mechanical systems and hardware and or software used during normal measurement operation.

(e) Except for system breakdowns, repairs, calibration checks, and zero and span adjustments required under paragraph (d) of this section, all continuous monitoring systems shall be in continuous operation and shall meet minimum frequency of operation requirements as follows:

(1) All continuous monitoring systems referenced by paragraph (c) of this section for measuring opacity of emissions shall complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

(2) All continuous monitoring systems referenced by paragraph (c) of this section for measuring emissions, except opacity, shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(f) All continuous monitoring systems or monitoring devices shall be installed such that representative measurements of emissions or process parameters from the affected facility are obtained. Additional procedures for location of continuous monitoring systems contained in the applicable Performance Specifications of appendix B of this part shall be used.

(g) When the effluents from a single affected facility or two or more affected facilities subject to the same emission standards are combined before being released to the atmosphere, the owner or operator may install applicable continuous monitoring systems on each effluent or on the combined effluent. When the affected facilities are not subject to the same emission standards, separate continuous monitoring systems shall be installed on each effluent. When the effluent from one affected facility is released to the atmosphere through more than one point, the owner or operator shall install an applicable continuous monitoring system on each separate effluent unless the installation of fewer systems is approved by the Administrator. When more than one continuous monitoring system is used to measure the emissions from one affected facility (e.g., multiple breechings, multiple outlets), the owner or operator shall report the results as required from each continuous monitoring system.

(h)

(1) Owners or operators of all continuous monitoring systems for measurement of opacity shall reduce all data to 6-minute averages and for continuous monitoring systems other than opacity to 1-hour averages for time periods as defined in § 60.2. Six-minute opacity averages shall be calculated from 36 or more data points equally spaced over each 6-minute period.

(2) For continuous monitoring systems other than opacity, 1-hour averages shall be computed as follows, except that the provisions pertaining to the validation of partial operating hours are only applicable for affected facilities that are required by the applicable subpart to include partial hours in the emission calculations:

(i) Except as provided under paragraph (h)(2)(iii) of this section, for a full operating hour (any clock hour with 60 minutes of unit operation), at least four valid data points are required to calculate the hourly average, *i.e.*, one data point in each of the 15-minute quadrants of the hour.

(ii) Except as provided under paragraph (h)(2)(iii) of this section, for a partial operating hour (any clock hour with less than 60 minutes of unit operation), at least one valid data point in each 15-minute quadrant of the hour in which the unit operates is required to calculate the hourly average.

(iii) For any operating hour in which required maintenance or quality-assurance activities are performed:

(A) If the unit operates in two or more quadrants of the hour, a minimum of two valid data points, separated by at least 15 minutes, is required to calculate the hourly average; or

(B) If the unit operates in only one quadrant of the hour, at least one valid data point is required to calculate the hourly average.

(iv) If a daily calibration error check is failed during any operating hour, all data for that hour shall be invalidated, unless a subsequent calibration error test is passed in the same hour and the requirements

of paragraph (h)(2)(iii) of this section are met, based solely on valid data recorded after the successful calibration.

(v) For each full or partial operating hour, all valid data points shall be used to calculate the hourly average.

(vi) Except as provided under paragraph (h)(2)(vii) of this section, data recorded during periods of continuous monitoring system breakdown, repair, calibration checks, and zero and span adjustments shall not be included in the data averages computed under this paragraph.

(vii) Owners and operators complying with the requirements of § 60.7(f)(1) or (2) must include any data recorded during periods of monitor breakdown or malfunction in the data averages.

(viii) When specified in an applicable subpart, hourly averages for certain partial operating hours shall not be computed or included in the emission averages (e.g., hours with < 30 minutes of unit operation under § 60.47b(d)).

(ix) Either arithmetic or integrated averaging of all data may be used to calculate the hourly averages. The data may be recorded in reduced or nonreduced form (e.g., ppm pollutant and percent O₂ or ng/J of pollutant).

(3) All excess emissions shall be converted into units of the standard using the applicable conversion procedures specified in the applicable subpart. After conversion into units of the standard, the data may be rounded to the same number of significant digits used in the applicable subpart to specify the emission limit.

(i) After receipt and consideration of written application, the Administrator may approve alternatives to any monitoring procedures or requirements of this part including, but not limited to the following:

(1) Alternative monitoring requirements when installation of a continuous monitoring system or monitoring device specified by this part would not provide accurate measurements due to liquid water or other interferences caused by substances in the effluent gases.

(2) Alternative monitoring requirements when the affected facility is infrequently operated.

(3) Alternative monitoring requirements to accommodate continuous monitoring systems that require additional measurements to correct for stack moisture conditions.

(4) Alternative locations for installing continuous monitoring systems or monitoring devices when the owner or operator can demonstrate that installation at alternate locations will enable accurate and representative measurements.

(5) Alternative methods of converting pollutant concentration measurements to units of the standards.

(6) Alternative procedures for performing daily checks of zero and span drift that do not involve use of span gases or test cells.

(7) Alternatives to the A.S.T.M. test methods or sampling procedures specified by any subpart.

(8) Alternative continuous monitoring systems that do not meet the design or performance requirements in Performance Specification 1, appendix B, but adequately demonstrate a definite and consistent relationship between its measurements and the measurements of opacity by a system complying with the requirements in Performance Specification 1. The Administrator may require that such demonstration be performed for each affected facility.

(9) Alternative monitoring requirements when the effluent from a single affected facility or the combined effluent from two or more affected facilities is released to the atmosphere through more than one point.

(j) An alternative to the relative accuracy (RA) test specified in Performance Specification 2 of appendix B may be requested as follows:

(1) An alternative to the reference method tests for determining RA is available for sources with emission rates demonstrated to be less than 50 percent of the applicable standard. A source owner or operator may petition the Administrator to waive the RA test in Section 8.4 of Performance Specification 2 and substitute the procedures in Section 16.0 if the results of a performance test conducted according to the requirements in § 60.8 of this subpart or other tests performed following the criteria in § 60.8 demonstrate that the emission rate of the pollutant of interest in the units of the applicable standard is less than 50 percent of the applicable standard. For sources subject to standards expressed as control efficiency levels, a source owner or operator may petition the Administrator to waive the RA test and substitute the procedures in Section 16.0 of Performance Specification 2 if the control device exhaust emission rate is less than 50 percent of the level needed to meet the control efficiency requirement. The alternative procedures do not apply if the continuous emission monitoring system is used to determine compliance continuously with the applicable standard. The petition to waive the RA test shall include a detailed description of the procedures to be applied. Included shall be location and procedure for conducting the alternative, the concentration or response levels of the alternative RA materials, and the other equipment checks included in the alternative procedure. The Administrator will review the petition for completeness and applicability. The determination to grant a waiver will depend on the intended use of the CEMS data (e.g., data collection purposes other than NSPS) and may require specifications more stringent than in Performance Specification 2 (e.g., the applicable emission limit is more stringent than NSPS).

(2) The waiver of a CEMS RA test will be reviewed and may be rescinded at such time, following successful completion of the alternative RA procedure, that the CEMS data indicate that the source emissions are approaching the level. The criterion for reviewing the waiver is the collection of CEMS data showing that emissions have exceeded 70 percent of the applicable standard for seven, consecutive, averaging periods as specified by the applicable regulation(s). For sources subject to standards expressed as control efficiency levels, the criterion for reviewing the waiver is the collection of CEMS data showing that exhaust emissions have exceeded 70 percent of the level needed to meet the control efficiency requirement for seven, consecutive, averaging periods as specified by the applicable regulation(s) [e.g., §§ 60.45(g) (2) and (3), 60.73(e), and 60.84(e)]. It is the responsibility of the source operator to maintain records and determine the level of emissions relative to the criterion on the waiver of RA testing. If this criterion is exceeded, the owner or operator must notify the Administrator within 10 days of such occurrence and include a description of the nature and cause of the increasing emissions. The Administrator will review the notification and may rescind the waiver and require the owner or operator to conduct a RA test of the CEMS as specified in Section 8.4 of Performance Specification 2.

Editorial Note: For Federal Register citations affecting § 60.13, see the List of CFR Sections Affected, which appears in the Finding Aids section of the printed volume and at www.govinfo.gov.

§ 60.14 Modification.

(a) Except as provided under paragraphs (e) and (f) of this section, any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification within the meaning of section 111 of the Act. Upon modification, an existing facility shall become an affected facility for each pollutant to which a standard applies and for which there is an increase in the emission rate to the atmosphere.

(b) Emission rate shall be expressed as kg/hr of any pollutant discharged into the atmosphere for which a standard is applicable. The Administrator shall use the following to determine emission rate:

(1) Emission factors as specified in the latest issue of "Compilation of Air Pollutant Emission Factors," EPA Publication No. AP-42, or other emission factors determined by the Administrator to be superior to AP-42 emission factors, in cases where utilization of emission factors demonstrates that the emission level resulting from the physical or operational change will either clearly increase or clearly not increase.

(2) Material balances, continuous monitor data, or manual emission tests in cases where utilization of emission factors as referenced in paragraph (b)(1) of this section does not demonstrate to the Administrator's satisfaction whether the emission level resulting from the physical or operational change will either clearly increase or clearly not increase, or where an owner or operator demonstrates to the Administrator's satisfaction that there are reasonable grounds to dispute the result obtained by the Administrator utilizing emission factors as referenced in paragraph (b)(1) of this section. When the emission rate is based on results from manual emission tests or continuous monitoring systems, the procedures specified in appendix C of this part shall be used to determine whether an increase in emission rate has occurred. Tests shall be conducted under such conditions as the Administrator shall specify to the owner or operator based on representative performance of the facility. At least three valid test runs must be conducted before and at least three after the physical or operational change. All operating parameters which may affect emissions must be held constant to the maximum feasible degree for all test runs.

(c) The addition of an affected facility to a stationary source as an expansion to that source or as a replacement for an existing facility shall not by itself bring within the applicability of this part any other facility within that source.

(d) [Reserved]

(e) The following shall not, by themselves, be considered modifications under this part:

(1) Maintenance, repair, and replacement which the Administrator determines to be routine for a source category, subject to the provisions of paragraph (c) of this section and § 60.15.

(2) An increase in production rate of an existing facility, if that increase can be accomplished without a capital expenditure on that facility.

(3) An increase in the hours of operation.

(4) Use of an alternative fuel or raw material if, prior to the date any standard under this part becomes applicable to that source type, as provided by § 60.1, the existing facility was designed to accommodate that alternative use. A facility shall be considered to be designed to accommodate an alternative fuel or raw material if that use could be accomplished under the facility's construction specifications as amended prior to the change. Conversion to coal required for energy considerations, as specified in section 111(a)(8) of the Act, shall not be considered a modification.

(5) The addition or use of any system or device whose primary function is the reduction of air pollutants, except when an emission control system is removed or is replaced by a system which the Administrator determines to be less environmentally beneficial.

(6) The relocation or change in ownership of an existing facility.

(f) Special provisions set forth under an applicable subpart of this part shall supersede any conflicting provisions of this section.

(g) Within 180 days of the completion of any physical or operational change subject to the control measures specified in paragraph (a) of this section, compliance with all applicable standards must be achieved.

(h) No physical change, or change in the method of operation, at an existing electric utility steam generating unit shall be treated as a modification for the purposes of this section provided that such change does not increase the

maximum hourly emissions of any pollutant regulated under this section above the maximum hourly emissions achievable at that unit during the 5 years prior to the change.

(i) Repowering projects that are awarded funding from the Department of Energy as permanent clean coal technology demonstration projects (or similar projects funded by EPA) are exempt from the requirements of this section provided that such change does not increase the maximum hourly emissions of any pollutant regulated under this section above the maximum hourly emissions achievable at that unit during the five years prior to the change.

(j)

(1) Repowering projects that qualify for an extension under section 409(b) of the Clean Air Act are exempt from the requirements of this section, provided that such change does not increase the actual hourly emissions of any pollutant regulated under this section above the actual hourly emissions achievable at that unit during the 5 years prior to the change.

(2) This exemption shall not apply to any new unit that:

(i) Is designated as a replacement for an existing unit;

(ii) Qualifies under section 409(b) of the Clean Air Act for an extension of an emission limitation compliance date under section 405 of the Clean Air Act; and

(iii) Is located at a different site than the existing unit.

(k) The installation, operation, cessation, or removal of a temporary clean coal technology demonstration project is exempt from the requirements of this section. A *temporary clean coal control technology demonstration project*, for the purposes of this section is a clean coal technology demonstration project that is operated for a period of 5 years or less, and which complies with the State implementation plan for the State in which the project is located and other requirements necessary to attain and maintain the national ambient air quality standards during the project and after it is terminated.

(l) The reactivation of a very clean coal-fired electric utility steam generating unit is exempt from the requirements of this section.

§ 60.15 Reconstruction.

(a) An existing facility, upon reconstruction, becomes an affected facility, irrespective of any change in emission rate.

(b) "Reconstruction" means the replacement of components of an existing facility to such an extent that:

(1) The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, and

(2) It is technologically and economically feasible to meet the applicable standards set forth in this part.

(c) "Fixed capital cost" means the capital needed to provide all the depreciable components.

(d) If an owner or operator of an existing facility proposes to replace components, and the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, he shall notify the Administrator of the proposed replacements. The notice must be postmarked 60 days (or as soon as practicable) before construction of the replacements is commenced and must include the following information:

(1) Name and address of the owner or operator.

(2) The location of the existing facility.

- (3) A brief description of the existing facility and the components which are to be replaced.
- (4) A description of the existing air pollution control equipment and the proposed air pollution control equipment.
- (5) An estimate of the fixed capital cost of the replacements and of constructing a comparable entirely new facility.
- (6) The estimated life of the existing facility after the replacements.
- (7) A discussion of any economic or technical limitations the facility may have in complying with the applicable standards of performance after the proposed replacements.
- (e) The Administrator will determine, within 30 days of the receipt of the notice required by paragraph (d) of this section and any additional information he may reasonably require, whether the proposed replacement constitutes reconstruction.
- (f) The Administrator's determination under paragraph (e) shall be based on:
 - (1) The fixed capital cost of the replacements in comparison to the fixed capital cost that would be required to construct a comparable entirely new facility;
 - (2) The estimated life of the facility after the replacements compared to the life of a comparable entirely new facility;
 - (3) The extent to which the components being replaced cause or contribute to the emissions from the facility; and
 - (4) Any economic or technical limitations on compliance with applicable standards of performance which are inherent in the proposed replacements.
- (g) Individual subparts of this part may include specific provisions which refine and delimit the concept of reconstruction set forth in this section.

§ 60.16 Priority list.

Prioritized Major Source Categories	
Priority Number ¹	Source Category
1.	Synthetic Organic Chemical Manufacturing Industry (SOCMI) and Volatile Organic Liquid Storage Vessels and Handling Equipment
	(a) SOCMI unit processes
	(b) Volatile organic liquid (VOL) storage vessels and handling equipment
	(c) SOCMI fugitive sources
	(d) SOCMI secondary sources
2.	Industrial Surface Coating: Cans
3.	Petroleum Refineries: Fugitive Sources
4.	Industrial Surface Coating: Paper

Prioritized Major Source Categories	
Priority Number ¹	Source Category
5.	Dry Cleaning
	(a) Perchloroethylene
	(b) Petroleum solvent
6.	Graphic Arts
7.	Polymers and Resins: Acrylic Resins
8.	Mineral Wool (Deleted)
9.	Stationary Internal Combustion Engines
10.	Industrial Surface Coating: Fabric
11.	Industrial-Commercial-Institutional Steam Generating Units.
12.	Incineration: Non-Municipal (Deleted)
13.	Non-Metallic Mineral Processing
14.	Metallic Mineral Processing
15.	Secondary Copper (Deleted)
16.	Phosphate Rock Preparation
17.	Foundries: Steel and Gray Iron
18.	Polymers and Resins: Polyethylene
19.	Charcoal Production
20.	Synthetic Rubber
	(a) Tire manufacture
	(b) SBR production
21.	Vegetable Oil
22.	Industrial Surface Coating: Metal Coil
23.	Petroleum Transportation and Marketing
24.	By-Product Coke Ovens
25.	Synthetic Fibers

Prioritized Major Source Categories	
Priority Number ¹	Source Category
26.	Plywood Manufacture
27.	Industrial Surface Coating: Automobiles
28.	Industrial Surface Coating: Large Appliances
29.	Crude Oil and Natural Gas Production
30.	Secondary Aluminum
31.	Potash (Deleted)
32.	Lightweight Aggregate Industry: Clay, Shale, and Slate ²
33.	Glass
34.	Gypsum
35.	Sodium Carbonate
36.	Secondary Zinc (Deleted)
37.	Polymers and Resins: Phenolic
38.	Polymers and Resins: Urea-Melamine
39.	Ammonia (Deleted)
40.	Polymers and Resins: Polystyrene
41.	Polymers and Resins: ABS-SAN Resins
42.	Fiberglass
43.	Polymers and Resins: Polypropylene
44.	Textile Processing
45.	Asphalt Processing and Asphalt Roofing Manufacture
46.	Brick and Related Clay Products
47.	Ceramic Clay Manufacturing (Deleted)
48.	Ammonium Nitrate Fertilizer
49.	Castable Refractories (Deleted)
50.	Borax and Boric Acid (Deleted)

Prioritized Major Source Categories	
Priority Number ¹	Source Category
51.	Polymers and Resins: Polyester Resins
52.	Ammonium Sulfate
53.	Starch
54.	Perlite
55.	Phosphoric Acid: Thermal Process (Deleted)
56.	Uranium Refining
57.	Animal Feed Defluorination (Deleted)
58.	Urea (for fertilizer and polymers)
59.	Detergent (Deleted)
<i>Other Source Categories</i>	
Lead acid battery manufacture ³	
Organic solvent cleaning ³	
Industrial surface coating: metal furniture ³	
Stationary gas turbines ⁴	
Municipal solid waste landfills ⁴	
¹ Low numbers have highest priority, e.g., No. 1 is high priority, No. 59 is low priority.	
² Formerly titled "Sintering: Clay and Fly Ash".	
³ Minor source category, but included on list since an NSPS is being developed for that source category.	
⁴ Not prioritized, since an NSPS for this major source category has already been promulgated.	

§ 60.17 Incorporations by reference.

(a)

(1) 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 U.S. Environmental Protection Agency (EPA) must publish a document in the Federal Register and the material must be available to the public. All approved incorporation by reference (IBR) material is available for inspection at the EPA and at the National Archives and Records Administration (NARA). Contact the EPA at: EPA Docket Center, Public Reading Room, EPA WJC West, Room 3334, 1301 Constitution Ave. NW, Washington, DC; phone: (202) 566-1744. For information on the availability of this material at NARA, visit www.archives.gov/federal-register/cfr/ibr-locations or email fr.inspection@nara.gov.

(2) The IBR material may be obtained from the sources in the following paragraphs of this section or from one or more private resellers listed in this paragraph (a)(2). For material that is no longer commercially available, contact: the EPA (see paragraph (a)(1) of this section).

(i) Accuris Standards Store, 321 Inverness Drive, South Englewood, CO 80112; phone: (800) 332-6077; website: <https://store accuristech.com>.

(ii) American National Standards Institute (ANSI), see paragraph (d) of this section.

(iii) GlobalSpec, 257 Fuller Road, Suite NFE 1100, Albany, NY 12203-3621; phone: (800) 261-2052; website: <https://standards globalspec.com>.

(iv) Nimonik Document Center, 401 Roland Way, Suite 224, Oakland, CA 94624; phone (650) 591-7600; email: info@document-center.com; website: www.document-center.com.

(v) Techstreet, phone: (855) 999-9870; email: store@techstreet.com; website: www.techstreet.com.

(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.

(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 National Standards Institute (ANSI), 25 West 43rd Street, Fourth Floor, New York, NY 10036-7417; phone: (212) 642-4980; email: info@ansi.org; website: www.ansi.org.

(1) ANSI No. C12.20-2010 American National Standard for Electricity Meters—0.2 and 0.5 Accuracy Classes (Approved August 31, 2010); IBR approved for §§ 60.5535(d); 60.5535a(d); 60.5860b(a).

(2) [Reserved]

(e) American Petroleum Institute (API), 200 Massachusetts Ave. NW, Suite 1100, Washington, DC 20001; phone: (202) 682-8000; website: www.api.org.

(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 14—Natural Gas Fluids Measurement, Section 1—Collecting and Handling of Natural Gas Samples for Custody Transfer, 7th Edition, May 2016, IBR approved for § 60.4415(a).

(3) 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).

(f) 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).

(g) American Society of Mechanical Engineers (ASME), Two Park Avenue, New York, NY 10016-5990; phone: (800) 843-2763; email: *CustomerCare@asme.org*; website: *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(b), (d), (f), and (g); 60.106a(a); 60.107a(a), (c), and (d); 60.275(e); 60.275a(e); 60.275b(e); tables 1 and 3 to subpart EEEE; tables 2 and 4 to subpart FFFF; table 2 to subpart JJJJ; §§ 60.285a(f); 60.396(a); 60.614a(b); 60.664a(b); 60.704(b); 60.704a(b); 60.2145(s) and (t); 60.2710(s) and (t); 60.2730(q); 60.4415(a); 60.4900(b); 60.5220(b); tables 1 and 2 to subpart LLLL; tables 2 and 3 to subpart MMMM; §§ 60.5406(c); 60.5406a(c); 60.5406b(c); 60.5407a(g); 60.5407b(g); 60.5413(b); 60.5413a(b) and (d); 60.5413b(d) and (d); 60.5413c(b) and (d).

(15) ASME PTC 22-2014, Gas Turbines: Performance Test Codes, (Issued December 31, 2014); IBR approved for §§ 60.5580; 60.5580a.

(16) ASME PTC 46-1996, Performance Test Code on Overall Plant Performance, (Issued October 15, 1997); IBR approved for §§ 60.5580; 60.5580a.

(17) 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).

(h) ASTM International, 100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428-2959; phone: (800) 262-1373; website: www.astm.org.

(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); 60.5401(f); 60.5401a(f); 60.5402b(d); 60.5402c(d).

(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 D240-19, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter, approved November 1, 2019; IBR approved for § 60.485b(g).
- (29) 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.
- (30) 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.
- (31) 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).
- (32) 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).
- (33) 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.
- (34) 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.
- (35) 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.
- (36) 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.
- (37) 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.
- (38) ASTM D388-99 (Reapproved 2004)^{e1}(ASTM D388-99R04), Standard Classification of Coals by Rank, (Approved June 1, 2004); IBR approved for §§ 60.41; 60.45(f); 60.41Da; 60.41b; 60.41c; 60.251; 60.5580; 60.5580a.
- (39) ASTM D396-78, Standard Specification for Fuel Oils, IBR approved for §§ 60.41b, 60.41c, 60.111(b), and 60.111a(b).

- (40) ASTM D396-89, Standard Specification for Fuel Oils, IBR approved for §§ 60.41b, 60.41c, 60.111(b), and 60.111a(b).
- (41) ASTM D396-90, Standard Specification for Fuel Oils, IBR approved for §§ 60.41b, 60.41c, 60.111(b), and 60.111a(b).
- (42) ASTM D396-92, Standard Specification for Fuel Oils, IBR approved for §§ 60.41b, 60.41c, 60.111(b), and 60.111a(b).
- (43) ASTM D396-98, Standard Specification for Fuel Oils, (Approved April 10, 1998); IBR approved for §§ 60.41b; 60.41c; 60.111(b); 60.111a(b); 60.5580; 60.5580a.
- (44) ASTM D975-78, Standard Specification for Diesel Fuel Oils, IBR approved for §§ 60.111(b) and 60.111a(b).
- (45) ASTM D975-96, Standard Specification for Diesel Fuel Oils, IBR approved for §§ 60.111(b) and 60.111a(b).
- (46) ASTM D975-98a, Standard Specification for Diesel Fuel Oils, IBR approved for §§ 60.111(b) and 60.111a(b).
- (47) ASTM D975-08a, Standard Specification for Diesel Fuel Oils, (Approved October 1, 2008); IBR approved for §§ 60.41b; 60.41c; 60.5580; 60.5580a.
- (48) ASTM D1072-80, Standard Test Method for Total Sulfur in Fuel Gases, IBR approved for § 60.335(b).
- (49) ASTM D1072-90 (Reapproved 1994), Standard Test Method for Total Sulfur in Fuel Gases, IBR approved for § 60.335(b).
- (50) ASTM D1072-90 (Reapproved 1999), Standard Test Method for Total Sulfur in Fuel Gases, IBR approved for § 60.4415(a).
- (51) 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).
- (52) 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).
- (53) 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.
- (54) 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.
- (55) ASTM D1266-87, Standard Test Method for Sulfur in Petroleum Products (Lamp Method), IBR approved for §§ 60.106(j) and 60.335(b).
- (56) ASTM D1266-91, Standard Test Method for Sulfur in Petroleum Products (Lamp Method), IBR approved for §§ 60.106(j) and 60.335(b).
- (57) ASTM D1266-98, Standard Test Method for Sulfur in Petroleum Products (Lamp Method), IBR approved for §§ 60.106(j) and 60.335(b).

(58) ASTM D1266-98 (Reapproved 2003)^{ε, 1} Standard Test Method for Sulfur in Petroleum Products (Lamp Method), IBR approved for § 60.4415(a).

(59) 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-7 to part 60: Method 24, Section 6.1; and Method 24A, Sections 6.5 and 7.1.

(60) ASTM D1475-90, Standard Test Method for Density of Paint, Varnish Lacquer, and Related Products, IBR approved for § 60.435(d), appendix A-7 to part 60: Method 24, Section 6.1; and Method 24A, §§ 6.5 and 7.1.

(61) ASTM D1475-13, Standard Test Method for Density of Liquid Coatings, Inks, and Related Products, Approved November 1, 2013; IBR approved for § 60.393a(f).

(62) 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.

(63) 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.

(64) 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.

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

(66) 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.

(67) 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.

(68) 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).

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

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

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

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

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

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

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

- (76) ASTM D1945-96, Standard Method for Analysis of Natural Gas by Gas Chromatography, IBR approved for § 60.45(f).
- (77) 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); 60.5413(d); 60.5413a(d); 60.5413b(d); 60.5413c(d).
- (78) ASTM D1945-14 (Reapproved 2019), Standard Test Method for Analysis of Natural Gas by Gas Chromatography, approved December 1, 2019; IBR approved for § 60.485b(g).
- (79) 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).
- (80) 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).
- (81) 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).
- (82) 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.
- (83) 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.
- (84) 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.
- (85) 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.
- (86) 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.
- (87) 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.
- (88) 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.
- (89) 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.
- (90) 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.
- (91) 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.
- (92) ASTM D2369-81, Standard Test Method for Volatile Content of Coatings, IBR approved for appendix A-7 to part 60: Method 24, Section 6.2.
- (93) ASTM D2369-87, Standard Test Method for Volatile Content of Coatings, IBR approved for appendix A-7 to part 60: Method 24, Section 6.2.
- (94) ASTM D2369-90, Standard Test Method for Volatile Content of Coatings, IBR approved for appendix A-7 to part 60: Method 24, Section 6.2.

- (95) ASTM D2369-92, Standard Test Method for Volatile Content of Coatings, IBR approved for appendix A-7 to part 60: Method 24, Section 6.2.
- (96) ASTM D2369-93, Standard Test Method for Volatile Content of Coatings, IBR approved for appendix A-7 to part 60: Method 24, Section 6.2.
- (97) ASTM D2369-95, Standard Test Method for Volatile Content of Coatings, IBR approved for appendix A-7 to part 60: Method 24, Section 6.2.
- (98) ASTM D2369-10 (Reapproved 2015)e1, Standard Test Method for Volatile Content of Coatings, (Approved June 1, 2015); IBR approved for appendix A-7 to part 60: Method 24, Section 6.2.
- (99) ASTM D2369-20, Standard Test Method for Volatile Content of Coatings, Approved June 1, 2020; IBR approved for §§ 60.393a(f); 60.723(b); 60.724(a); 60.725(b); 60.723a(b); 60.724a(a); 60.725a(b).
- (100) 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).
- (101) 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).
- (102) ASTM D2504-67, Noncondensable Gases in C3 and Lighter Hydrocarbon Products by Gas Chromatography, IBR approved for §§ 60.485(g) and 60.485a(g).
- (103) ASTM D2504-77, Noncondensable Gases in C3 and Lighter Hydrocarbon Products by Gas Chromatography, IBR approved for §§ 60.485(g) and 60.485a(g).
- (104) 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).
- (105) ASTM D2584-68(Reapproved 1985), Standard Test Method for Ignition Loss of Cured Reinforced Resins, IBR approved for § 60.685(c).
- (106) ASTM D2584-94, Standard Test Method for Ignition Loss of Cured Reinforced Resins, IBR approved for § 60.685(c).
- (107) 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).
- (108) 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).
- (109) 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).
- (110) 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).
- (111) ASTM D2622-05, Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-Ray Fluorescence Spectrometry, IBR approved for § 60.4415(a).
- (112) ASTM D2697-22, Standard Test Method for Volume Nonvolatile Matter in Clear or Pigmented Coatings, Approved July 1, 2022; IBR approved for §§ 60.393a(g); 60.723(b); 60.724(a); 60.725(b); 60.723a(b); 60.724a(a); 60.725a(b).
- (113) ASTM D2879-83, Test Method for Vapor Pressure-Temperature Relationship and Initial Decomposition Temperature of Liquids by Isoteniscope, approved 1983; IBR approved for §§ 60.111b(f); 60.116b(e) and (f); 60.485(e); 60.485a(e); 60.5403b(d); 60.5406c(d).

(114) ASTM D2879-96, Test Method for Vapor Pressure-Temperature Relationship and Initial Decomposition Temperature of Liquids by Isoteniscope, approved 1996; IBR approved for §§ 60.111b(f); 60.116b(e) and (f); 60.485(e); 60.485a(e); 60.5403b(d); 60.5406c(d).

(115) ASTM D2879-97, Test Method for Vapor Pressure-Temperature Relationship and Initial Decomposition Temperature of Liquids by Isoteniscope, approved 1997; IBR approved for §§ 60.111b(f); 60.116b(e) and (f); 60.485(e); 60.485a(e); 60.5403b(d); 60.5406c(d).

(116) ASTM D2879-23, Standard Test Method for Vapor Pressure-Temperature Relationship and Initial Decomposition Temperature of Liquids by Isoteniscope, approved December 1, 2019; IBR approved for § 60.485b(e).

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

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

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

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

(121) ASTM D2986-71, Standard Method for Evaluation of Air, Assay Media by the Monodisperse DOP (Diethyl 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.

(122) ASTM D2986-78, Standard Method for Evaluation of Air, Assay Media by the Monodisperse DOP (Diethyl 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.

(123) ASTM D2986-95a, Standard Method for Evaluation of Air, AssaMedia by the Monodisperse DOP (Diethyl 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.

(124) 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.

(125) 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.

(126) 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.

(127) 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.

(128) 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.

(129) 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.

(130) 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).

- (131) ASTM D3178-89, Standard Test Methods for Carbon and Hydrogen in the Analysis Sample of Coal and Coke, IBR approved for § 60.45(f).
- (132) ASTM D3246-81, Standard Test Method for Sulfur in Petroleum Gas by Oxidative Microcoulometry, IBR approved for § 60.335(b).
- (133) ASTM D3246-92, Standard Test Method for Sulfur in Petroleum Gas by Oxidative Microcoulometry, IBR approved for § 60.335(b).
- (134) ASTM D3246-96, Standard Test Method for Sulfur in Petroleum Gas by Oxidative Microcoulometry, IBR approved for § 60.335(b).
- (135) ASTM D3246-05, Standard Test Method for Sulfur in Petroleum Gas by Oxidative Microcoulometry, IBR approved for § 60.4415(a)(1).
- (136) 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.
- (137) 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.
- (138) 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.
- (139) 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.
- (140) 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.
- (141) 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.
- (142) ASTM D3370-76, Standard Practices for Sampling Water, IBR approved for § 60.564(j).
- (143) ASTM D3370-95a, Standard Practices for Sampling Water, IBR approved for § 60.564(j).
- (144) 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); 60.5413(d); 60.5413a(d); 60.5413b(d); 60.5413c(d).
- (145) ASTM D3699-08, Standard Specification for Kerosine, including Appendix X1, (Approved September 1, 2008); IBR approved for §§ 60.41b; 60.41c; 60.5580; 60.5580a.
- (146) 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.
- (147) 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.
- (148) 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.
- (149) 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.
- (150) 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.

- (151) 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.
- (152) 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.
- (153) ASTM D4057-95 (Reapproved 2000), Standard Practice for Manual Sampling of Petroleum and Petroleum Products, IBR approved for § 60.4415(a).
- (154) 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).
- (155) 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).
- (156) 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).
- (157) 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.
- (158) ASTM D4177-95 (Reapproved 2000), Standard Practice for Automatic Sampling of Petroleum and Petroleum Products, IBR approved for § 60.4415(a).
- (159) 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.
- (160) 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.
- (161) 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.
- (162) 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).
- (163) 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).
- (164) 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.
- (165) 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.
- (166) 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.
- (167) 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.
- (168) 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).

- (169) 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).
- (170) 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).
- (171) 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).
- (172) 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).
- (173) ASTM D4809-18, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method), approved July 1, 2018; IBR approved for § 60.485b(g).
- (174) 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).
- (175) ASTM D4840-99(2018)e1 Standard Guide for Sample Chain-of-Custody Procedures, approved August 2018; IBR approved for Appendix A-7: Method 23.
- (176) 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); 60.5413(d); 60.5413a(d); 60.5413b(d); 60.5413c(d).
- (177) ASTM D5066-91, Standard Test Method for Determination of the Transfer Efficiency Under Production Conditions for Spray Application of Automotive Paints—Weight Basis, Approved June 1, 2017; IBR approved for § 60.393a(h).
- (178) ASTM D5087-02 (Reapproved 2021), 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), Approved February 1, 2021; IBR approved for § 60.397a(e); appendix A to subpart MMA.
- (179) ASTM D5287-97 (Reapproved 2002), Standard Practice for Automatic Sampling of Gaseous Fuels, IBR approved for § 60.4415(a).
- (180) 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.
- (181) 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).
- (182) 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).
- (183) 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.
- (184) 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).
- (185) ASTM D5623-19, Standard Test Method for Sulfur Compounds in Light Petroleum Liquids by Gas Chromatography and Sulfur Selective Detection, (Approved July 1, 2019); IBR approved for § 60.4415(a).

- (186) ASTM D5762-02, Standard Test Method for Nitrogen in Petroleum and Petroleum Products by Boat-Inlet Chemiluminescence, IBR approved for § 60.335(b).
- (187) 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.
- (188) 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.
- (189) ASTM D5965-02 (Reapproved 2013), Standard Test Methods for Specific Gravity of Coating Powders, Approved June 1, 2013; IBR approved for § 60.393a(f).
- (190) ASTM D6093-97 (Reapproved 2016), Standard Test Method for Percent Volume Nonvolatile Matter in Clear or Pigmented Coatings Using a Helium Gas Pycnometer, Approved December 1, 2016; IBR approved for §§ 60.393a(g); 60.723(b); 60.724(a); 60.725(b); 60.723a(b); 60.724a(a); 60.725a(b).
- (191) ASTM D6216-20, Standard Practice for Opacity Monitor Manufacturers to Certify Conformance with Design and Performance Specifications, approved September 1, 2020; IBR approved for appendix B to part 60.
- (192) 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).
- (193) 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.
- (194) ASTM D6266-00a (Reapproved 2017), Standard 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), Approved July 1, 2017; IBR approved for § 60.397a(e).
- (195) 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, table 2 to subpart JJJJ, and § 60.4245(d).
- (196) ASTM D6348-12e1, Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy, approved February 1, 2012; IBR approved for § 60.5413c(b).
- (197) 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).
- (198) ASTM D6377-20, Standard Test Method for Determination of Vapor Pressure of Crude Oil: VPCR_x (Expansion Method), (Approved June 1, 2020); IBR approved for § 60.113c.
- (199) ASTM-D6378-22, Standard Test Method for Determination of Vapor Pressure (VPX) of Petroleum Products, Hydrocarbons, and Hydrocarbon-Oxygenate Mixtures (Triple Expansion Method), (Approved July 1, 2022); IBR approved for § 60.113c.
- (200) 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.
- (201) ASTM D6420-18, Standard Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography-Mass Spectrometry, approved November 1, 2018, IBR approved for §§ 60.485(g); 60.485a(g); 60.485b(g); 60.611a; 60.614(b) and (e); 60.614a(b) and (e), 60.664(b) and (e); 60.664a(b) and (f); 60.700(c); 60.704(b) (d), and (h); 60.705(l); 60.704a(b) and (f).

(202) 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).

(203) 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 JJJ, §§ 60.5413(b) and (d), and 60.5413a(b).

(204) ASTM D6522-11 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 December 1, 2011), IBR approved for § 60.37f(a), 60.766(a).

(205) ASTM D6522-20, 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 June 1, 2020; IBR approved for §§ 60.5413b(b); 60.5413c(b).

(206) 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).

(207) 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).

(208) 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, 60.41c, 60.5580, and 60.5580a.

(209) 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.

(210) 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 § 60.56c(b).

(211) ASTM D6784-16, Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method), approved March 1, 2016; IBR approved for appendix B to part 60.

(212) ASTM D6911-15 Standard Guide for Packaging and Shipping Environmental Samples for Laboratory Analysis, approved January 15, 2015; IBR approved for Appendix A-7: Method 23; Appendix A-8: Method 30B.

(213) ASTM D7039-15a, Standard Test Method for Sulfur in Gasoline, Diesel Fuel, Jet Fuel, Kerosine, Boideisel, Biodiesel Blends, and Gasoline-Ethanol Blends by Monochromatic Wavelength Dispersive X-ray Fluorescence Spectrometry, (Approved July 1, 2015); IBR approved for § 60.4415(a).

(214) 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, 60.41c, 60.5580, and 60.5580a.

(215) ASTM D7520-16, Standard Test Method for Determining the Opacity of a Plume in the Outdoor Ambient Atmosphere, approved April 1, 2016; IBR approved for §§ 60.123(c)(6); 60.123(c)(6)(i); 60.123(c)(6)(ii); 60.123(c)(6)(v); 60.123a(c)(6)(ii); 60.123a(c)(6)(ii)(A); 60.123a(c)(6)(ii)(B); 60.123a(c)(6)(ii)(E); 60.271(k);

60.272(a) and (b); 60.273(c) and (d); 60.274(h); 60.275(e); 60.276(c); 60.271a; 60.272a(a) and (b); 60.273a(c) and (d); 60.274a(h); 60.275a(e); 60.276a(f); 60.271b; 60.272b(a) and (b); 60.273b(c) and (d); 60.274b(h); 60.275b(e); 60.276b(f); 60.374a(d).

(216) 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).

(217) 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).

(218) ASTM E168-92, General Techniques of Infrared Quantitative Analysis, IBR approved for §§ 60.485a(d), 60.593(b), 60.593a(b), 60.632(f), 60.5400, 60.5400a(f).

(219) ASTM E168-16 (Reapproved 2023), Standard Practices for General Techniques of Infrared Quantitative Analysis, approved January 1, 2023; IBR approved for § 60.485b(d).

(220) 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).

(221) 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).

(222) 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), 60.5400(f), and 60.5400a(f).

(223) ASTM E169-16 (Reapproved 2022), Standard Practices for General Techniques of Ultraviolet-Visible Quantitative Analysis, approved November 1, 2022; IBR approved for § 60.485b(d).

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

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

(226) 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), 60.5400a(f), 60.5406(b), 60.5406a(b)(3), 60.5400b(a)(2), 60.5401b(a)(2), 60.5406b(b)(3), 60.5400c(a), and 60.5401c(a).

(227) ASTM E260-96 (Reapproved 2019), Standard Practice for Packed Column Gas Chromatography, approved September 1, 2029; IBR approved for § 60.485b(d).

(228) ASTM E617-13, Standard Specification for Laboratory Weights and Precision Mass Standards, approved May 1, 2013, IBR approved for appendix A-3: Methods 4, 5, 5H, 5I, and appendix A-8: Method 29.

(229) ASTM E871-82 (Reapproved 2013), Standard Test Method for Moisture Analysis of Particulate Wood Fuels, (Approved August 15, 2013), IBR approved for appendix A-8: method 28R.

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

(231) ASTM E2515-11, Standard Test Method for Determination of Particulate Matter Emissions Collected by a Dilution Tunnel, (Approved November 1, 2011), IBR approved for § 60.534 and § 60.5476.

(232) ASTM E2618-13 Standard Test Method for Measurement of Particulate Matter Emissions and Heating Efficiency of Outdoor Solid Fuel-Fired Hydronic Heating Appliances, (Approved September 1, 2013), IBR approved for § 60.5476.

(233) ASTM E2779-10, Standard Test Method for Determining Particulate Matter Emissions from Pellet Heaters, (Approved October 1, 2010), IBR approved for § 60.534.

(234) ASTM E2780-10, Standard Test Method for Determining Particulate Matter Emissions from Wood Heaters, (Approved October 1, 2010), IBR approved for appendix A: method 28R.

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

(i) Association of Official Analytical Chemists, 1111 North 19th Street, Suite 210, Arlington, VA 22209; phone: (301) 927-7077; website: <https://www.aoac.org/>.

(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]

(j) CSA Group (CSA) (formerly Canadian Standards Association), 178 Rexdale Boulevard, Toronto, Ontario, Canada; phone: (800) 463-6727; website: <https://shop.csa.ca>.

(1) CSA B415.1-10, Performance Testing of Solid-fuel-burning Heating Appliances, (March 2010), IBR approved for §§ 60.534; 60.5476.

(2) [Reserved]

(k) U.S. Environmental Protection Agency (EPA), 1200 Pennsylvania Avenue NW, Washington, DC 20460; phone: (202) 272-0167; website: www.epa.gov/aboutepa/forms/contact-epa.

(1) EPA-453/R-08-002, Protocol for Determining the Daily Volatile Organic Compound Emission Rate of Automobile and Light-Duty Truck Primer-Surfacer and Topcoat Operations, September 2008, Office of Air Quality Planning and Standards (OAQPS); IBR approved for §§ 60.393a(e) and (h); 60.395a(k); 60.397a(e); appendix A to subpart MMA.

(2) EPA-454/B-08-002, Quality Assurance Handbook for Air Pollution Measurement Systems; Volume IV: Meteorological Measurements, Version 2.0 (Final), March 2008; IBR approved for appendix K to this part.

(3) EPA-454/R-98-015, Office of Air Quality Planning and Standards (OAQPS), Fabric Filter Bag Leak Detection Guidance, September 1997; IBR approved for §§ 60.124(f); 60.124a(f); 60.273(e); 60.273a(e); 60.273b(e); 60.373a(b); 60.2145(r); 60.2710(r); 60.2944(c), 60.3043(c), 60.4880(b); 60.5200(b). (Available from: <https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=2000D5T6.pdf>).

(4) EPA-600/R-12/531, EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards, May 2012; IBR approved for §§ 60.5413(d); 60.5413a(d); 60.5413b(d); 60.5413c(d).

(5) In EPA Publication No. SW-846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods (Available from: www.epa.gov/hw-sw846/sw-846-compendium):

(i) SW-846-6010D, Inductively Coupled Plasma-Optical Emission Spectrometry, Revision 5, July 2018; IBR approved for appendix A-5 to this part.

(ii) SW-846-6020B, Inductively Coupled Plasma-Mass Spectrometry, Revision 2, July 2014; IBR approved for appendix A-5 to this part.

(l) European Standards (EN), European Committee for Standardization, Management Centre, Avenue Marnix 17, B-1000 Brussels, Belgium; phone: + 32 2 550 08 11; website: <https://www.en-standard.eu>.

(1) DIN EN 303-5:2012E (EN 303-5), Heating boilers—Part 5: Heating boilers for solid fuels, manually and automatically stoked, nominal heat output of up to 500 kW—Terminology, requirements, testing and marking, (October 2012), IBR approved for § 60.5476.

(2) [Reserved]

(m) GPA Midstream Association, 6060 American Plaza, Suite 700, Tulsa, OK 74135; phone: (918) 493-3872; website: www.gpamidstream.org.

(1) GPA Midstream Standard 2140-17 (GPA 2140-17), Liquefied Petroleum Gas Specifications and Test Methods, (Revised 2017), IBR approved for § 60.4415(a).

(2) GPA Midstream Standard 2166-17 (GPA 2166-17), Obtaining Natural Gas Samples for Analysis by Gas Chromatography, (Reaffirmed 2017), IBR approved for § 60.4415(a).

(3) 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).

(4) GPA Standard 2174-14 (GPA 2174-14), Obtaining Liquid Hydrocarbon Samples for Analysis by Gas Chromatography, (Revised 2014), IBR approved for § 60.4415(a).

(5) GPA Standard 2261-19 (GPA 2261-19), Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography, (Revised 2019), IBR approved for § 60.4415(a).

(6) 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).

(n) International Organization for Standardization (ISO), 1, ch. de la Voie-Creuse, Case postale 56, CH-1211 Geneva 20, Switzerland; phone: + 41 22 749 01 11; website: www.iso.org.

(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) ISO 2314:2009(E), Gas turbines-Acceptance tests, Third edition (December 15, 2009), IBR approved for §§ 60.5580; 60.5580a.

(3) 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).

(4) ISO 10715:1997(E), Natural gas—Sampling guidelines, (First Edition, June 1, 1997), IBR approved for § 60.4415(a).

(o) National Technical Information Services (NTIS), 5285 Port Royal Road, Springfield, Virginia 22161.

(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]

(p) 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]

(q) Pacific Lumber Inspection Bureau (formerly West Coast Lumber Inspection Bureau), 1010 South 336th Street #210, Federal Way, WA 98003; phone: (253) 835.3344; website: www.plib.org.

(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]

(r) Technical Association of the Pulp and Paper Industry (TAPPI), 15 Technology Parkway South, Suite 115, Peachtree Corners, GA 30092; phone (800) 332-8686; website: www.tappi.org.

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

(2) [Reserved]

(s) 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]

(t) 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]

Editorial Note: For Federal Register citations affecting § 60.17, see the List of CFR Sections Affected, which appears in the Finding Aids section of the printed volume and at www.govinfo.gov.

§ 60.18 General control device and work practice requirements.

(a) *Introduction.*

(1) This section contains requirements for control devices used to comply with applicable subparts of 40 CFR parts 60 and 61. The requirements are placed here for administrative convenience and apply only to facilities covered by subparts referring to this section.

(2) This section also contains requirements for an alternative work practice used to identify leaking equipment. This alternative work practice is placed here for administrative convenience and is available to all subparts in 40 CFR parts 60, 61, 63, and 65 that require monitoring of equipment with a 40 CFR part 60, appendix A-7, Method 21 monitor.

(b) *Flares.* Paragraphs (c) through (f) apply to flares.

(c)

(1) Flares shall be designed for and operated with no visible emissions as determined by the methods specified in paragraph (f), except for periods not to exceed a total of 5 minutes during any 2 consecutive hours.

(2) Flares shall be operated with a flame present at all times, as determined by the methods specified in paragraph (f).

(3) An owner/operator has the choice of adhering to either the heat content specifications in paragraph (c)(3)(ii) of this section and the maximum tip velocity specifications in paragraph (c)(4) of this section, or adhering to the requirements in paragraph (c)(3)(i) of this section.

(i)

(A) Flares shall be used that have a diameter of 3 inches or greater, are nonassisted, have a hydrogen content of 8.0 percent (by volume), or greater, and are designed for and operated with an exit velocity less than 37.2 m/sec (122 ft/sec) and less than the velocity, $V_{\max}$, as determined by the following equation:

$$V_{\max} = (X_{H_2} - K_1) * K_2$$

Where:

$V_{\max}$ = Maximum permitted velocity, m/sec.

K_1 = Constant, 6.0 volume-percent hydrogen.

K_2 = Constant, 3.9(m/sec)/volume-percent hydrogen.

X_{H_2} = The volume-percent of hydrogen, on a wet basis, as calculated by using the American Society for Testing and Materials (ASTM) Method D1946-77. (Incorporated by reference as specified in § 60.17).

(B) The actual exit velocity of a flare shall be determined by the method specified in paragraph (f)(4) of this section.

(ii) Flares shall be used only with the net heating value of the gas being combusted being 11.2 MJ/scm (300 Btu/scf) or greater if the flare is steam-assisted or air-assisted; or with the net heating value of the gas being combusted being 7.45 MJ/scm (200 Btu/scf) or greater if the flare is nonassisted. The net heating value of the gas being combusted shall be determined by the methods specified in paragraph (f)(3) of this section.

(4)

(i) Steam-assisted and nonassisted flares shall be designed for and operated with an exit velocity, as determined by the methods specified in paragraph (f)(4) of this section, less than 18.3 m/sec (60 ft/sec), except as provided in paragraphs (c)(4) (ii) and (iii) of this section.

(ii) Steam-assisted and nonassisted flares designed for and operated with an exit velocity, as determined by the methods specified in paragraph (f)(4), equal to or greater than 18.3 m/sec (60 ft/sec) but less than 122 m/sec (400 ft/sec) are allowed if the net heating value of the gas being combusted is greater than 37.3 MJ/scm (1,000 Btu/scf).

(iii) Steam-assisted and nonassisted flares designed for and operated with an exit velocity, as determined by the methods specified in paragraph (f)(4), less than the velocity, $V_{\max}$, as determined by the method specified in paragraph (f)(5), and less than 122 m/sec (400 ft/sec) are allowed.

(5) Air-assisted flares shall be designed and operated with an exit velocity less than the velocity, $V_{\max}$, as determined by the method specified in paragraph (f)(6).

(6) Flares used to comply with this section shall be steam-assisted, air-assisted, or nonassisted.

(d) Owners or operators of flares used to comply with the provisions of this subpart shall monitor these control devices to ensure that they are operated and maintained in conformance with their designs. Applicable subparts will provide provisions stating how owners or operators of flares shall monitor these control devices.

(e) Flares used to comply with provisions of this subpart shall be operated at all times when emissions may be vented to them.

(f)

- (1) Method 22 of appendix A to this part shall be used to determine the compliance of flares with the visible emission provisions of this subpart. The observation period is 2 hours and shall be used according to Method 22.
- (2) The presence of a flare pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame.
- (3) The net heating value of the gas being combusted in a flare shall be calculated using the following equation:

$$H_T = K \sum_{i=1}^n C_i H_i$$

where:

H_T = Net heating value of the sample, MJ/scm; where the net enthalpy per mole of offgas is based on combustion at 25 °C and 760 mm Hg, but the standard temperature for determining the volume corresponding to one mole is 20 °C;

$$K = \text{Constant}, 1.740 \times 10^{-7} \left(\frac{1}{\text{ppm}} \right) \left(\frac{\text{g mole}}{\text{scm}} \right) \left(\frac{\text{MJ}}{\text{kcal}} \right)$$

where the standard temperature for $\left(\frac{\text{g mole}}{\text{scm}} \right)$ is 20°C;

C_i = Concentration of sample component i in ppm on a wet basis, as measured for organics by Reference Method 18 and measured for hydrogen and carbon monoxide by ASTM D1946-77 or 90 (Reapproved 1994) (Incorporated by reference as specified in § 60.17); and

H_i = Net heat of combustion of sample component i , kcal/g mole at 25 °C and 760 mm Hg. The heats of combustion may be determined using ASTM D2382-76 or 88 or D4809-95 (incorporated by reference as specified in § 60.17) if published values are not available or cannot be calculated.

- (4) The actual exit velocity of a flare shall be determined by dividing the volumetric flowrate (in units of standard temperature and pressure), as determined by Reference Methods 2, 2A, 2C, or 2D as appropriate; by the unobstructed (free) cross sectional area of the flare tip.
- (5) The maximum permitted velocity, $V_{\max}$, for flares complying with paragraph (c)(4)(iii) shall be determined by the following equation.

$$\text{Log}_{10} (V_{\max}) = (H_T + 28.8)/31.7$$

$V_{\max}$ = Maximum permitted velocity, M/sec

28.8 = Constant

31.7 = Constant

H_T = The net heating value as determined in paragraph (f)(3).

- (6) The maximum permitted velocity, $V_{\max}$, for air-assisted flares shall be determined by the following equation.

$$V_{\max} = 8.706 + 0.7084 (H_T)$$

$V_{\max}$ = Maximum permitted velocity, m/sec

8.706 = Constant

0.7084 = Constant

H_T = The net heating value as determined in paragraph (f)(3).

(g) *Alternative work practice for monitoring equipment for leaks.* Paragraphs (g), (h), and (i) of this section apply to all equipment for which the applicable subpart requires monitoring with a 40 CFR part 60, appendix A-7, Method 21 monitor, except for closed vent systems, equipment designated as leakless, and equipment identified in the applicable subpart as having no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background. An owner or operator may use an optical gas imaging instrument instead of a 40 CFR part 60, appendix A-7, Method 21 monitor. Requirements in the existing subparts that are specific to the Method 21 instrument do not apply under this section. All other requirements in the applicable subpart that are not addressed in paragraphs (g), (h), and (i) of this section apply to this standard. For example, equipment specification requirements, and non-Method 21 instrument recordkeeping and reporting requirements in the applicable subpart continue to apply. The terms defined in paragraphs (g)(1) through (5) of this section have meanings that are specific to the alternative work practice standard in paragraphs (g), (h), and (i) of this section.

(1) *Applicable subpart* means the subpart in 40 CFR parts 60, 61, 63, or 65 that requires monitoring of equipment with a 40 CFR part 60, appendix A-7, Method 21 monitor.

(2) *Equipment* means pumps, valves, pressure relief valves, compressors, open-ended lines, flanges, connectors, and other equipment covered by the applicable subpart that require monitoring with a 40 CFR part 60, appendix A-7, Method 21 monitor.

(3) *Imaging* means making visible emissions that may otherwise be invisible to the naked eye.

(4) *Optical gas imaging instrument* means an instrument that makes visible emissions that may otherwise be invisible to the naked eye.

(5) *Repair* means that equipment is adjusted, or otherwise altered, in order to eliminate a leak.

(6) *Leak* means:

(i) Any emissions imaged by the optical gas instrument;

(ii) Indications of liquids dripping;

(iii) Indications by a sensor that a seal or barrier fluid system has failed; or

(iv) Screening results using a 40 CFR part 60, appendix A-7, Method 21 monitor that exceed the leak definition in the applicable subpart to which the equipment is subject.

(h) The alternative work practice standard for monitoring equipment for leaks is available to all subparts in 40 CFR parts 60, 61, 63, and 65 that require monitoring of equipment with a 40 CFR part 60, appendix A-7, Method 21 monitor.

(1) An owner or operator of an affected source subject to CFR parts 60, 61, 63, or 65 can choose to comply with the alternative work practice requirements in paragraph (i) of this section instead of using the 40 CFR part 60, appendix A-7, Method 21 monitor to identify leaking equipment. The owner or operator must document the equipment, process units, and facilities for which the alternative work practice will be used to identify leaks.

(2) Any leak detected when following the leak survey procedure in paragraph (i)(3) of this section must be identified for repair as required in the applicable subpart.

(3) If the alternative work practice is used to identify leaks, re-screening after an attempted repair of leaking equipment must be conducted using either the alternative work practice or the 40 CFR part 60, appendix A-7, Method 21 monitor at the leak definition required in the applicable subpart to which the equipment is subject.

(4) The schedule for repair is as required in the applicable subpart.

(5) When this alternative work practice is used for detecting leaking equipment, choose one of the monitoring frequencies listed in Table 1 to subpart A of this part in lieu of the monitoring frequency specified for regulated equipment in the applicable subpart. Reduced monitoring frequencies for good performance are not applicable when using the alternative work practice.

(6) When this alternative work practice is used for detecting leaking equipment the following are not applicable for the equipment being monitored:

(i) Skip period leak detection and repair;

(ii) Quality improvement plans; or

(iii) Complying with standards for allowable percentage of valves and pumps to leak.

(7) When the alternative work practice is used to detect leaking equipment, the regulated equipment in paragraph (h)(1)(i) of this section must also be monitored annually using a 40 CFR part 60, appendix A-7, Method 21 monitor at the leak definition required in the applicable subpart. The owner or operator may choose the specific monitoring period (for example, first quarter) to conduct the annual monitoring. Subsequent monitoring must be conducted every 12 months from the initial period. Owners or operators must keep records of the annual Method 21 screening results, as specified in paragraph (i)(4)(vii) of this section.

(i) An owner or operator of an affected source who chooses to use the alternative work practice must comply with the requirements of paragraphs (i)(1) through (i)(5) of this section.

(1) Instrument Specifications. The optical gas imaging instrument must comply with the requirements in (i)(1)(i) and (i)(1)(ii) of this section.

(i) Provide the operator with an image of the potential leak points for each piece of equipment at both the detection sensitivity level and within the distance used in the daily instrument check described in paragraph (i)(2) of this section. The detection sensitivity level depends upon the frequency at which leak monitoring is to be performed.

(ii) Provide a date and time stamp for video records of every monitoring event.

(2) Daily Instrument Check. On a daily basis, and prior to beginning any leak monitoring work, test the optical gas imaging instrument at the mass flow rate determined in paragraph (i)(2)(i) of this section in accordance with the procedure specified in paragraphs (i)(2)(ii) through (i)(2)(iv) of this section for each camera configuration used during monitoring (for example, different lenses used), unless an alternative method to demonstrate daily instrument checks has been approved in accordance with paragraph (i)(2)(v) of this section.

(i) Calculate the mass flow rate to be used in the daily instrument check by following the procedures in paragraphs (i)(2)(i)(A) and (i)(2)(i)(B) of this section.

(A) For a specified population of equipment to be imaged by the instrument, determine the piece of equipment in contact with the lowest mass fraction of chemicals that are detectable, within the distance to be used in paragraph (i)(2)(iv)(B) of this section, at or below the standard detection sensitivity level.

(B) Multiply the standard detection sensitivity level, corresponding to the selected monitoring frequency in Table 1 of subpart A of this part, by the mass fraction of detectable chemicals from

the stream identified in paragraph (i)(2)(i)(A) of this section to determine the mass flow rate to be used in the daily instrument check, using the following equation.

$$E_{dic} = (E_{sds}) \sum_{i=1}^k x_i$$

Where:

E_{dic} = Mass flow rate for the daily instrument check, grams per hour

x_i = Mass fraction of detectable chemical(s) i seen by the optical gas imaging instrument, within the distance to be used in paragraph (i)(2)(iv)(B) of this section, at or below the standard detection sensitivity level, E_{sds} .

E_{sds} = Standard detection sensitivity level from Table 1 to subpart A, grams per hour

k = Total number of detectable chemicals emitted from the leaking equipment and seen by the optical gas imaging instrument.

(ii) Start the optical gas imaging instrument according to the manufacturer's instructions, ensuring that all appropriate settings conform to the manufacturer's instructions.

(iii) Use any gas chosen by the user that can be viewed by the optical gas imaging instrument and that has a purity of no less than 98 percent.

(iv) Establish a mass flow rate by using the following procedures:

(A) Provide a source of gas where it will be in the field of view of the optical gas imaging instrument.

(B) Set up the optical gas imaging instrument at a recorded distance from the outlet or leak orifice of the flow meter that will not be exceeded in the actual performance of the leak survey. Do not exceed the operating parameters of the flow meter.

(C) Open the valve on the flow meter to set a flow rate that will create a mass emission rate equal to the mass rate specified in paragraph (i)(2)(i) of this section while observing the gas flow through the optical gas imaging instrument viewfinder. When an image of the gas emission is seen through the viewfinder at the required emission rate, make a record of the reading on the flow meter.

(v) Repeat the procedures specified in paragraphs (i)(2)(ii) through (i)(2)(iv) of this section for each configuration of the optical gas imaging instrument used during the leak survey.

(vi) To use an alternative method to demonstrate daily instrument checks, apply to the Administrator for approval of the alternative under § 60.13(i).

(3) Leak Survey Procedure. Operate the optical gas imaging instrument to image every regulated piece of equipment selected for this work practice in accordance with the instrument manufacturer's operating parameters. All emissions imaged by the optical gas imaging instrument are considered to be leaks and are subject to repair. All emissions visible to the naked eye are also considered to be leaks and are subject to repair.

(4) Recordkeeping. You must keep the records described in paragraphs (i)(4)(i) through (i)(4)(vii) of this section:

(i) The equipment, processes, and facilities for which the owner or operator chooses to use the alternative work practice.

- (ii) The detection sensitivity level selected from Table 1 to subpart A of this part for the optical gas imaging instrument.
 - (iii) The analysis to determine the piece of equipment in contact with the lowest mass fraction of chemicals that are detectable, as specified in paragraph (i)(2)(i)(A) of this section.
 - (iv) The technical basis for the mass fraction of detectable chemicals used in the equation in paragraph (i)(2)(i)(B) of this section.
 - (v) The daily instrument check. Record the distance, per paragraph (i)(2)(iv)(B) of this section, and the flow meter reading, per paragraph (i)(2)(iv)(C) of this section, at which the leak was imaged. Keep a video record of the daily instrument check for each configuration of the optical gas imaging instrument used during the leak survey (for example, the daily instrument check must be conducted for each lens used). The video record must include a time and date stamp for each daily instrument check. The video record must be kept for 5 years.
 - (vi) Recordkeeping requirements in the applicable subpart. A video record must be used to document the leak survey results. The video record must include a time and date stamp for each monitoring event. A video record can be used to meet the recordkeeping requirements of the applicable subparts if each piece of regulated equipment selected for this work practice can be identified in the video record. The video record must be kept for 5 years.
 - (vii) The results of the annual Method 21 screening required in paragraph (h)(7) of this section. Records must be kept for all regulated equipment specified in paragraph (h)(1) of this section. Records must identify the equipment screened, the screening value measured by Method 21, the time and date of the screening, and calibration information required in the existing applicable subpart.
- (5) Reporting. Submit the reports required in the applicable subpart. Submit the records of the annual Method 21 screening required in paragraph (h)(7) of this section to the Administrator via e-mail to CCG-AWP@EPA.GOV.

§ 60.19 General notification and reporting requirements.

- (a) For the purposes of this part, time periods specified in days shall be measured in calendar days, even if the word "calendar" is absent, unless otherwise specified in an applicable requirement.
- (b) For the purposes of this part, if an explicit postmark deadline is not specified in an applicable requirement for the submittal of a notification, application, report, or other written communication to the Administrator, the owner or operator shall postmark the submittal on or before the number of days specified in the applicable requirement. For example, if a notification must be submitted 15 days before a particular event is scheduled to take place, the notification shall be postmarked on or before 15 days preceding the event; likewise, if a notification must be submitted 15 days after a particular event takes place, the notification shall be delivered or postmarked on or before 15 days following the end of the event. The use of reliable non-Government mail carriers that provide indications of verifiable delivery of information required to be submitted to the Administrator, similar to the postmark provided by the U.S. Postal Service, or alternative means of delivery, including the use of electronic media, agreed to by the permitting authority, is acceptable.
- (c) Notwithstanding time periods or postmark deadlines specified in this part for the submittal of information to the Administrator by an owner or operator, or the review of such information by the Administrator, such time periods or deadlines may be changed by mutual agreement between the owner or operator and the Administrator. Procedures governing the implementation of this provision are specified in paragraph (f) of this section.
- (d) If an owner or operator of an affected facility in a State with delegated authority is required to submit periodic reports under this part to the State, and if the State has an established timeline for the submission of periodic reports that is consistent with the reporting frequency(ies) specified for such facility under this part, the owner or

operator may change the dates by which periodic reports under this part shall be submitted (without changing the frequency of reporting) to be consistent with the State's schedule by mutual agreement between the owner or operator and the State. The allowance in the previous sentence applies in each State beginning 1 year after the affected facility is required to be in compliance with the applicable subpart in this part. Procedures governing the implementation of this provision are specified in paragraph (f) of this section.

(e) If an owner or operator supervises one or more stationary sources affected by standards set under this part and standards set under part 61, part 63, or both such parts of this chapter, he/she may arrange by mutual agreement between the owner or operator and the Administrator (or the State with an approved permit program) a common schedule on which periodic reports required by each applicable standard shall be submitted throughout the year. The allowance in the previous sentence applies in each State beginning 1 year after the stationary source is required to be in compliance with the applicable subpart in this part, or 1 year after the stationary source is required to be in compliance with the applicable 40 CFR part 61 or part 63 of this chapter standard, whichever is latest. Procedures governing the implementation of this provision are specified in paragraph (f) of this section.

(f)

(1)

(i) Until an adjustment of a time period or postmark deadline has been approved by the Administrator under paragraphs (f)(2) and (f)(3) of this section, the owner or operator of an affected facility remains strictly subject to the requirements of this part.

(ii) An owner or operator shall request the adjustment provided for in paragraphs (f)(2) and (f)(3) of this section each time he or she wishes to change an applicable time period or postmark deadline specified in this part.

(2) Notwithstanding time periods or postmark deadlines specified in this part for the submittal of information to the Administrator by an owner or operator, or the review of such information by the Administrator, such time periods or deadlines may be changed by mutual agreement between the owner or operator and the Administrator. An owner or operator who wishes to request a change in a time period or postmark deadline for a particular requirement shall request the adjustment in writing as soon as practicable before the subject activity is required to take place. The owner or operator shall include in the request whatever information he or she considers useful to convince the Administrator that an adjustment is warranted.

(3) If, in the Administrator's judgment, an owner or operator's request for an adjustment to a particular time period or postmark deadline is warranted, the Administrator will approve the adjustment. The Administrator will notify the owner or operator in writing of approval or disapproval of the request for an adjustment within 15 calendar days of receiving sufficient information to evaluate the request.

(4) If the Administrator is unable to meet a specified deadline, he or she will notify the owner or operator of any significant delay and inform the owner or operator of the amended schedule.

Table 1 to Subpart A of Part 60—Detection Sensitivity Levels (grams per hour)

Monitoring frequency per subpart ^a	Detection sensitivity level
Bi-Monthly	60
Semi-Quarterly	85
Monthly	100

^a When this alternative work practice is used to identify leaking equipment, the owner or operator must choose one of

Monitoring frequency per subpart ^a	Detection sensitivity level
the monitoring frequencies listed in this table in lieu of the monitoring frequency specified in the applicable subpart. Bi-monthly means every other month. Semi-quarterly means twice per quarter. Monthly means once per month.	

Appendix C. 40 CFR Part 60, Subpart JJJJ—Standards of Performance for Stationary Spark Ignition Internal Combustion Engines

§ 60.4230 Am I subject to this subpart?

(a) The provisions of this subpart are applicable to manufacturers, owners, and operators of stationary spark ignition (SI) internal combustion engines (ICE) as specified in paragraphs (a)(1) through (6) of this section. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator.

(1) Manufacturers of stationary SI ICE with a maximum engine power less than or equal to 19 kilowatt (KW) (25 horsepower (HP)) that are manufactured on or after July 1, 2008.

(2) Manufacturers of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) that are gasoline fueled or that are rich burn engines fueled by liquefied petroleum gas (LPG), where the date of manufacture is:

(i) On or after July 1, 2008; or

(ii) On or after January 1, 2009, for emergency engines.

(3) Manufacturers of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) that are not gasoline fueled and are not rich burn engines fueled by LPG, where the manufacturer participates in the voluntary manufacturer certification program described in this subpart and where the date of manufacture is:

(i) On or after July 1, 2007, for engines with a maximum engine power greater than or equal to 500 HP (except lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP);

(ii) On or after January 1, 2008, for lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP;

(iii) On or after July 1, 2008, for engines with a maximum engine power less than 500 HP; or

(iv) On or after January 1, 2009, for emergency engines.

(4) Owners and operators of stationary SI ICE that commence construction after June 12, 2006, where the stationary SI ICE are manufactured:

(i) On or after July 1, 2007, for engines with a maximum engine power greater than or equal to 500 HP (except lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP);

(ii) on or after January 1, 2008, for lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP;

(iii) on or after July 1, 2008, for engines with a maximum engine power less than 500 HP; or

(iv) on or after January 1, 2009, for emergency engines with a maximum engine power greater than 19 KW (25 HP).

(5) Owners and operators of stationary SI ICE that are modified or reconstructed after June 12, 2006, and any person that modifies or reconstructs any stationary SI ICE after June 12, 2006.

(6) The provisions of § 60.4236 of this subpart are applicable to all owners and operators of stationary SI ICE that commence construction after June 12, 2006.

(b) The provisions of this subpart are not applicable to stationary SI ICE being tested at an engine test cell/stand.

(c) If you are an owner or operator of an area source subject to this subpart, you are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart.

Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart as applicable.

(d) For the purposes of this subpart, stationary SI ICE using alcohol-based fuels are considered gasoline engines.

(e) Stationary SI ICE may be eligible for exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C (or the exemptions described in 40 CFR parts 1048 and 1054, for engines that would need to be certified to standards in those parts), except that owners and operators, as well as manufacturers, may be eligible to request an exemption for national security.

(f) Owners and operators of facilities with internal combustion engines that are acting as temporary replacement units and that are located at a stationary source for less than 1 year and that have been properly certified as meeting the standards that would be applicable to such engine under the appropriate nonroad engine provisions, are not required to meet any other provisions under this subpart with regard to such engines.

Emission Standards for Manufacturers

§ 60.4231 What emission standards must I meet if I am a manufacturer of stationary SI internal combustion engines or equipment containing such engines?

(a) Stationary SI internal combustion engine manufacturers must certify their stationary SI ICE with a maximum engine power less than or equal to 19 KW (25 HP) manufactured on or after July 1, 2008 to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 1054, as follows:

If engine displacement is . . .	and manufacturing dates are . . .	the engine must meet the following non-handheld emission standards identified in 40 CFR part 1054 and related requirements:
(1) Below 225 cc	July 1, 2008 to December 31, 2011	Phase 2.
(2) Below 225 cc	January 1, 2012 or later	Phase 3.
(3) At or above 225 cc	July 1, 2008 to December 31, 2010	Phase 2.
(4) At or above 225 cc	January 1, 2011 or later	Phase 3.

(b) Stationary SI internal combustion engine manufacturers must certify their stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) (except emergency stationary ICE with a maximum engine power greater than 25 HP and less than 130 HP) that use gasoline and that are manufactured on or after the applicable date in § 60.4230(a)(2), or manufactured on or after the applicable date in § 60.4230(a)(4) for emergency stationary ICE with a maximum engine power greater than or equal to 130 HP, to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 1048. Stationary SI internal combustion engine manufacturers must certify their emergency stationary SI ICE with a maximum engine power greater than 25 HP and less than 130 HP that use gasoline and that are manufactured on or after the applicable date in § 60.4230(a)(4) to the Phase 1 emission standards in 40 CFR part 1054, appendix I, applicable to class II engines, and other requirements for new nonroad SI engines in 40 CFR part 1054. Stationary SI internal combustion engine manufacturers may certify their stationary SI ICE with a maximum engine power less than or equal to 30 KW (40 HP) with a total displacement less than or equal to 1,000 cubic centimeters (cc) that use gasoline to the certification emission standards and other requirements as appropriate for new nonroad SI engines in 40 CFR part 1054.

(c) Stationary SI internal combustion engine manufacturers must certify their stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) (except emergency stationary ICE with a maximum engine power greater than 25 HP and less than 130 HP) that are rich burn engines that use LPG and that are manufactured on or after the applicable date in § 60.4230(a)(2), or manufactured on or after the applicable date in § 60.4230(a)(4) for emergency stationary ICE with a maximum engine power greater than or equal to 130 HP, to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 1048. Stationary SI internal combustion engine manufacturers must certify their emergency stationary SI ICE greater than 25 HP and less than 130 HP that are rich burn engines that use LPG and that are manufactured on or after the applicable date in § 60.4230(a)(4) to the Phase 1 emission standards in 40 CFR part 1054, appendix I, applicable to class II engines, and other requirements for new nonroad SI engines in 40 CFR part 1054. Stationary SI internal combustion engine manufacturers may certify their stationary SI ICE with a maximum engine power less than or equal to 30 KW (40 HP) with a total displacement less than or equal to 1,000 cc that are rich burn engines that use LPG to the certification emission standards and other requirements as appropriate for new nonroad SI engines in 40 CFR part 1054.

(d) Stationary SI internal combustion engine manufacturers who choose to certify their stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) and less than 75 KW (100 HP) (except gasoline and rich burn engines that use LPG and emergency stationary ICE with a maximum engine power greater than 25 HP and less than 130 HP) under the voluntary manufacturer certification program described in this subpart must certify those engines to the certification emission standards for new nonroad SI engines in 40 CFR part 1048. Stationary SI internal combustion engine manufacturers who choose to certify their emergency stationary SI ICE greater than 25 HP and less than 130 HP (except gasoline and rich burn engines that use LPG), must certify those engines to the Phase 1 emission standards in 40 CFR part 1054, appendix I, applicable to class II engines, for new nonroad SI engines in 40 CFR part 1054. Stationary SI internal combustion engine manufacturers may certify their stationary SI ICE with a maximum engine power less than or equal to 30 KW (40 HP) with a total displacement less than or equal to 1,000 cc (except gasoline and rich burn engines that use LPG) to the certification emission standards and other requirements as appropriate for new nonroad SI engines in 40 CFR part 1054. For stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) and less than 75 KW (100 HP) (except gasoline and rich burn engines that use LPG and emergency stationary ICE with a maximum engine power greater than 25 HP and less than 130 HP) manufactured prior to January 1, 2011, manufacturers may choose to certify these engines to the standards in Table 1 to this subpart applicable to engines with a maximum engine power greater than or equal to 100 HP and less than 500 HP.

(e) Stationary SI internal combustion engine manufacturers who choose to certify their stationary SI ICE with a maximum engine power greater than or equal to 75 KW (100 HP) (except gasoline and rich burn engines that use LPG) under the voluntary manufacturer certification program described in this subpart must certify those engines to the emission standards in Table 1 to this subpart. Stationary SI internal combustion engine manufacturers may certify their stationary SI ICE with a maximum engine power greater than or equal to 75 KW (100 HP) that are lean burn engines that use LPG to the certification emission standards for new nonroad SI engines in 40 CFR part 1048. For stationary SI ICE with a maximum engine power greater than or equal to 100 HP (75 KW) and less than 500 HP (373 KW) manufactured prior to January 1, 2011, and for stationary SI ICE with a maximum engine power greater than or equal to 500 HP (373 KW) manufactured prior to July 1, 2010, manufacturers may choose to certify these engines to the certification emission standards for new nonroad SI engines in 40 CFR part 1048 applicable to engines that are not severe duty engines.

(f) Manufacturers of equipment containing stationary SI internal combustion engines meeting the provisions of 40 CFR part 1054 must meet the provisions of 40 CFR part 1060, to the extent they apply to equipment manufacturers.

(g) Notwithstanding the requirements in paragraphs (a) through (c) of this section, stationary SI internal combustion engine manufacturers are not required to certify reconstructed engines; however manufacturers may

elect to do so. The reconstructed engine must be certified to the emission standards specified in paragraphs (a) through (e) of this section that are applicable to the model year, maximum engine power and displacement of the reconstructed stationary SI ICE.

§ 60.4232 How long must my engines meet the emission standards if I am a manufacturer of stationary SI internal combustion engines?

Engines manufactured by stationary SI internal combustion engine manufacturers must meet the emission standards as required in § 60.4231 during the certified emissions life of the engines.

Emission Standards for Owners and Operators

§ 60.4233 What emission standards must I meet if I am an owner or operator of a stationary SI internal combustion engine?

(a) Owners and operators of stationary SI ICE with a maximum engine power less than or equal to 19 KW (25 HP) manufactured on or after July 1, 2008, must comply with the emission standards in § 60.4231(a) for their stationary SI ICE.

(b) Owners and operators of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) manufactured on or after the applicable date in § 60.4230(a)(4) that use gasoline must comply with the emission standards in § 60.4231(b) for their stationary SI ICE.

(c) Owners and operators of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) manufactured on or after the applicable date in § 60.4230(a)(4) that are rich burn engines that use LPG must comply with the emission standards in § 60.4231(c) for their stationary SI ICE.

(d) Owners and operators of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) and less than 75 KW (100 HP) (except gasoline and rich burn engines that use LPG) must comply with the emission standards for field testing in 40 CFR 1048.101(c) for their non-emergency stationary SI ICE and with the emission standards in Table 1 to this subpart for their emergency stationary SI ICE. Owners and operators of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) and less than 75 KW (100 HP) manufactured prior to January 1, 2011, that were certified to the standards in Table 1 to this subpart applicable to engines with a maximum engine power greater than or equal to 100 HP and less than 500 HP, may optionally choose to meet those standards.

(e) Owners and operators of stationary SI ICE with a maximum engine power greater than or equal to 75 KW (100 HP) (except gasoline and rich burn engines that use LPG) must comply with the emission standards in Table 1 to this subpart for their stationary SI ICE. For owners and operators of stationary SI ICE with a maximum engine power greater than or equal to 100 HP (except gasoline and rich burn engines that use LPG) manufactured prior to January 1, 2011 that were certified to the certification emission standards in 40 CFR part 1048 applicable to engines that are not severe duty engines, if such stationary SI ICE was certified to a carbon monoxide (CO) standard above the standard in Table 1 to this subpart, then the owners and operators may meet the CO certification (not field testing) standard for which the engine was certified.

(f) Owners and operators of any modified or reconstructed stationary SI ICE subject to this subpart must meet the requirements as specified in paragraphs (f)(1) through (5) of this section.

(1) Owners and operators of stationary SI ICE with a maximum engine power less than or equal to 19 KW (25 HP), that are modified or reconstructed after June 12, 2006, must comply with emission standards in § 60.4231(a) for their stationary SI ICE. Engines with a date of manufacture prior to July 1, 2008 must comply with the emission standards specified in § 60.4231(a) applicable to engines manufactured on July 1, 2008.

(2) Owners and operators of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) that are gasoline engines and are modified or reconstructed after June 12, 2006, must comply with the emission

standards in § 60.4231(b) for their stationary SI ICE. Engines with a date of manufacture prior to July 1, 2008 (or January 1, 2009 for emergency engines) must comply with the emission standards specified in § 60.4231(b) applicable to engines manufactured on July 1, 2008 (or January 1, 2009 for emergency engines).

(3) Owners and operators of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) that are rich burn engines that use LPG, that are modified or reconstructed after June 12, 2006, must comply with the same emission standards as those specified in § 60.4231(c). Engines with a date of manufacture prior to July 1, 2008 (or January 1, 2009 for emergency engines) must comply with the emission standards specified in § 60.4231(c) applicable to engines manufactured on July 1, 2008 (or January 1, 2009 for emergency engines).

(4) Owners and operators of stationary SI natural gas and lean burn LPG engines with a maximum engine power greater than 19 KW (25 HP), that are modified or reconstructed after June 12, 2006, must comply with the same emission standards as those specified in paragraph (d) or (e) of this section, except that such owners and operators of non-emergency engines and emergency engines greater than or equal to 130 HP must meet a nitrogen oxides (NO_x) emission standard of 3.0 grams per HP-hour (g/HP-hr), a CO emission standard of 4.0 g/HP-hr (5.0 g/HP-hr for non-emergency engines less than 100 HP), and a volatile organic compounds (VOC) emission standard of 1.0 g/HP-hr, or a NO_x emission standard of 250 ppmvd at 15 percent oxygen (O₂), a CO emission standard 540 ppmvd at 15 percent O₂ (675 ppmvd at 15 percent O₂ for non-emergency engines less than 100 HP), and a VOC emission standard of 86 ppmvd at 15 percent O₂, where the date of manufacture of the engine is:

- (i) Prior to July 1, 2007, for non-emergency engines with a maximum engine power greater than or equal to 500 HP (except lean burn natural gas engines and LPG engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP);
- (ii) Prior to July 1, 2008, for non-emergency engines with a maximum engine power less than 500 HP;
- (iii) Prior to January 1, 2009, for emergency engines;
- (iv) Prior to January 1, 2008, for non-emergency lean burn natural gas engines and LPG engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP.

(5) Owners and operators of stationary SI landfill/digester gas ICE engines with a maximum engine power greater than 19 KW (25 HP), that are modified or reconstructed after June 12, 2006, must comply with the same emission standards as those specified in paragraph (e) of this section for stationary landfill/digester gas engines. Engines with maximum engine power less than 500 HP and a date of manufacture prior to July 1, 2008 must comply with the emission standards specified in paragraph (e) of this section for stationary landfill/digester gas ICE with a maximum engine power less than 500 HP manufactured on July 1, 2008. Engines with a maximum engine power greater than or equal to 500 HP (except lean burn engines greater than or equal to 500 HP and less than 1,350 HP) and a date of manufacture prior to July 1, 2007 must comply with the emission standards specified in paragraph (e) of this section for stationary landfill/digester gas ICE with a maximum engine power greater than or equal to 500 HP (except lean burn engines greater than or equal to 500 HP and less than 1,350 HP) manufactured on July 1, 2007. Lean burn engines greater than or equal to 500 HP and less than 1,350 HP with a date of manufacture prior to January 1, 2008 must comply with the emission standards specified in paragraph (e) of this section for stationary landfill/digester gas ICE that are lean burn engines greater than or equal to 500 HP and less than 1,350 HP and manufactured on January 1, 2008.

(g) Owners and operators of stationary SI wellhead gas ICE engines may petition the Administrator for approval on a case-by-case basis to meet emission standards no less stringent than the emission standards that apply to stationary emergency SI engines greater than 25 HP and less than 130 HP due to the presence of high sulfur levels in the fuel, as specified in Table 1 to this subpart. The request must, at a minimum, demonstrate that the fuel has high sulfur levels that prevent the use of aftertreatment controls and also that the owner has reasonably made all

attempts possible to obtain an engine that will meet the standards without the use of aftertreatment controls. The petition must request the most stringent standards reasonably applicable to the engine using the fuel.

(h) Owners and operators of stationary SI ICE that are required to meet standards that reference 40 CFR 1048.101 must, if testing their engines in use, meet the standards in that section applicable to field testing, except as indicated in paragraph (e) of this section.

§ 60.4234 How long must I meet the emission standards if I am an owner or operator of a stationary SI internal combustion engine?

Owners and operators of stationary SI ICE must operate and maintain stationary SI ICE that achieve the emission standards as required in § 60.4233 over the entire life of the engine.

Other Requirements for Owners and Operators

§ 60.4235 What fuel requirements must I meet if I am an owner or operator of a stationary SI gasoline fired internal combustion engine subject to this subpart?

Owners and operators of stationary SI ICE subject to this subpart that use gasoline must use gasoline that meets the per gallon sulfur limit in 40 CFR 1090.205.

§ 60.4236 What is the deadline for importing or installing stationary SI ICE produced in previous model years?

- (a) After July 1, 2010, owners and operators may not install stationary SI ICE with a maximum engine power of less than 500 HP that do not meet the applicable requirements in § 60.4233.
- (b) After July 1, 2009, owners and operators may not install stationary SI ICE with a maximum engine power of greater than or equal to 500 HP that do not meet the applicable requirements in § 60.4233, except that lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP that do not meet the applicable requirements in § 60.4233 may not be installed after January 1, 2010.
- (c) For emergency stationary SI ICE with a maximum engine power of greater than 19 KW (25 HP), owners and operators may not install engines that do not meet the applicable requirements in § 60.4233 after January 1, 2011.
- (d) In addition to the requirements specified in §§ 60.4231 and 60.4233, it is prohibited to import stationary SI ICE less than or equal to 19 KW (25 HP), stationary rich burn LPG SI ICE, and stationary gasoline SI ICE that do not meet the applicable requirements specified in paragraphs (a), (b), and (c) of this section, after the date specified in paragraph (a), (b), and (c) of this section.
- (e) The requirements of this section do not apply to owners and operators of stationary SI ICE that have been modified or reconstructed, and they do not apply to engines that were removed from one existing location and reinstalled at a new location.

§ 60.4237 What are the monitoring requirements if I am an owner or operator of an emergency stationary SI internal combustion engine?

- (a) Starting on July 1, 2010, if the emergency stationary SI internal combustion engine that is greater than or equal to 500 HP that was built on or after July 1, 2010, does not meet the standards applicable to non-emergency engines, the owner or operator must install a non-resettable hour meter.
- (b) Starting on January 1, 2011, if the emergency stationary SI internal combustion engine that is greater than or equal to 130 HP and less than 500 HP that was built on or after January 1, 2011, does not meet the standards applicable to non-emergency engines, the owner or operator must install a non-resettable hour meter.
- (c) If you are an owner or operator of an emergency stationary SI internal combustion engine that is less than 130 HP, was built on or after July 1, 2008, and does not meet the standards applicable to non-emergency engines, you must install a non-resettable hour meter upon startup of your emergency engine.

Compliance Requirements for Manufacturers

§ 60.4238 What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines ≤19 KW (25 HP) or a manufacturer of equipment containing such engines?

Stationary SI internal combustion engine manufacturers who are subject to the emission standards specified in § 60.4231(a) must certify their stationary SI ICE using the certification and testing procedures required in 40 CFR part 1054, subparts C and F. Manufacturers of equipment containing stationary SI internal combustion engines meeting the provisions of 40 CFR part 1054 must meet the provisions of 40 CFR part 1060, subpart C, to the extent they apply to equipment manufacturers.

§ 60.4239 What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines >19 KW (25 HP) that use gasoline or a manufacturer of equipment containing such engines?

Stationary SI internal combustion engine manufacturers who are subject to the emission standards specified in § 60.4231(b) must certify their stationary SI ICE using the certification procedures required in 40 CFR part 1048, subpart C, and must test their engines as specified in that part. Stationary SI internal combustion engine manufacturers who certify their stationary SI ICE with a maximum engine power less than or equal to 30 KW (40 HP) with a total displacement less than or equal to 1,000 cc to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 1054, and manufacturers of stationary SI emergency engines that are greater than 25 HP and less than 130 HP who meet the Phase 1 emission standards in 40 CFR part 1054, appendix I, applicable to class II engines, must certify their stationary SI ICE using the certification and testing procedures required in 40 CFR part 1054, subparts C and F. Manufacturers of equipment containing stationary SI internal combustion engines meeting the provisions of 40 CFR part 1054 must meet the provisions of 40 CFR part 1060, subpart C, to the extent they apply to equipment manufacturers.

§ 60.4240 What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines >19 KW (25 HP) that are rich burn engines that use LPG or a manufacturer of equipment containing such engines?

Stationary SI internal combustion engine manufacturers who are subject to the emission standards specified in § 60.4231(c) must certify their stationary SI ICE using the certification procedures required in 40 CFR part 1048, subpart C, and must test their engines as specified in that part. Stationary SI internal combustion engine manufacturers who certify their stationary SI ICE with a maximum engine power less than or equal to 30 KW (40 HP) with a total displacement less than or equal to 1,000 cc to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 1054, and manufacturers of stationary SI emergency engines that are greater than 25 HP and less than 130 HP who meet the Phase 1 emission standards in 40 CFR part 1054, appendix I, applicable to class II engines, must certify their stationary SI ICE using the certification and testing procedures required in 40 CFR part 1054, subparts C and F. Manufacturers of equipment containing stationary SI internal combustion engines meeting the provisions of 40 CFR part 1054 must meet the provisions of 40 CFR part 1060, subpart C, to the extent they apply to equipment manufacturers.

§ 60.4241 What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines participating in the voluntary certification program or a manufacturer of equipment containing such engines?

(a) Manufacturers of stationary SI internal combustion engines with a maximum engine power greater than 19 KW (25 HP) that do not use gasoline and are not rich burn engines that use LPG can choose to certify their engines to the emission standards in § 60.4231(d) or (e), as applicable, under the voluntary certification program described in this subpart. Manufacturers who certify their engines under the voluntary certification program must meet the requirements as specified in paragraphs (b) through (g) of this section. In addition, manufacturers of stationary SI internal combustion engines who choose to certify their engines under the voluntary certification program, must also meet the requirements as specified in § 60.4247. Manufacturers of stationary SI internal combustion engines who choose not to certify their engines under this section must notify the ultimate purchaser that testing requirements apply as described in § 60.4243(b)(2); manufacturers must keep a copy of this notification for five years after shipping each engine and make those documents available to EPA upon request.

(b) Manufacturers of engines other than those certified to standards in 40 CFR part 1054 must certify their stationary SI ICE using the certification procedures required in 40 CFR part 1048, subpart C, and must follow the same test procedures that apply to Large SI nonroad engines under 40 CFR part 1048, but must use the D-1 cycle of International Organization for Standardization 8178-4: 1996(E) (incorporated by reference, see § 60.17) or the test cycle requirements specified in Table 3 to 40 CFR 1048.505, except that Table 3 of 40 CFR 1048.505 applies to high load engines only. Manufacturers of any size may certify their stationary emergency engines at or above 130 hp using assigned deterioration factors established by EPA, consistent with 40 CFR 1048.240. Stationary SI internal combustion engine manufacturers who certify their stationary SI ICE with a maximum engine power less than or equal to 30 KW (40 HP) with a total displacement less than or equal to 1,000 cc to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 1054, and manufacturers of emergency engines that are greater than 25 HP and less than 130 HP who meet the Phase 1 standards in 40 CFR part 1054, appendix I, applicable to class II engines, must certify their stationary SI ICE using the certification and testing procedures required in 40 CFR part 1054, subparts C and F. Manufacturers of equipment containing stationary SI internal combustion engines meeting the provisions of 40 CFR part 1054 must meet the provisions of 40 CFR part 1060, subpart C, to the extent they apply to equipment manufacturers.

(c) Certification of stationary SI ICE to the emission standards specified in § 60.4231(d) or (e), as applicable, is voluntary, but manufacturers who decide to certify are subject to all of the requirements indicated in this subpart with regard to the engines included in their certification. Manufacturers must clearly label their stationary SI engines as certified or non-certified engines.

(d) Manufacturers of natural gas fired stationary SI ICE who conduct voluntary certification of stationary SI ICE to the emission standards specified in § 60.4231(d) or (e), as applicable, must certify their engines for operation using fuel that meets the definition of pipeline-quality natural gas. The fuel used for certifying stationary SI natural gas engines must meet the definition of pipeline-quality natural gas as described in § 60.4248. In addition, the manufacturer must provide information to the owner and operator of the certified stationary SI engine including the specifications of the pipeline-quality natural gas to which the engine is certified and what adjustments the owner or operator must make to the engine when installed in the field to ensure compliance with the emission standards.

(e) Manufacturers of stationary SI ICE that are lean burn engines fueled by LPG who conduct voluntary certification of stationary SI ICE to the emission standards specified in § 60.4231(d) or (e), as applicable, must certify their engines for operation using fuel that meets the specifications in 40 CFR 1065.720.

(f) Manufacturers may certify their engines for operation using gaseous fuels in addition to pipeline-quality natural gas; however, the manufacturer must specify the properties of that fuel and provide testing information showing that the engine will meet the emission standards specified in § 60.4231(d) or (e), as applicable, when operating on that fuel. The manufacturer must also provide instructions for configuring the stationary engine to meet the emission standards on fuels that do not meet the pipeline-quality natural gas definition. The manufacturer must also provide information to the owner and operator of the certified stationary SI engine regarding the configuration that is most conducive to reduced emissions where the engine will be operated on gaseous fuels with different quality than the fuel that it was certified to.

(g) A stationary SI engine manufacturer may certify an engine family solely to the standards applicable to landfill/digester gas engines as specified in § 60.4231(d) or (e), as applicable, but must certify their engines for operation using landfill/digester gas and must add a permanent label stating that the engine is for use only in landfill/digester gas applications. The label must be added according to the labeling requirements specified in 40 CFR 1048.135(b).

(h) For purposes of this subpart, when calculating emissions of volatile organic compounds, emissions of formaldehyde should not be included.

(i) For engines being certified to the voluntary certification standards in Table 1 of this subpart, the VOC measurement shall be made by following the procedures in 40 CFR part 1065, subpart C, to determine the total NMHC emissions. As an alternative, manufacturers may measure ethane, as well as methane, for excluding such levels from the total VOC measurement.

§ 60.4242 What other requirements must I meet if I am a manufacturer of stationary SI internal combustion engines or equipment containing stationary SI internal combustion engines or a manufacturer of equipment containing such engines?

(a) Stationary SI internal combustion engine manufacturers must meet the provisions of 40 CFR parts 1048, 1054, and 1068, as applicable, except that engines certified pursuant to the voluntary certification procedures in § 60.4241 are subject only to the provisions indicated in § 60.4247 and are permitted to provide instructions to owners and operators allowing for deviations from certified configurations, if such deviations are consistent with the provisions of § 60.4241(c) through (f). Manufacturers of equipment containing stationary SI internal combustion engines meeting the provisions of 40 CFR part 1054 must meet the provisions of 40 CFR part 1060, as applicable. Labels on engines certified to 40 CFR part 1048 must refer to stationary engines, rather than or in addition to nonroad engines, as appropriate.

(b) An engine manufacturer certifying an engine family or families to standards under this subpart that are identical to standards identified in 40 CFR part 1048 or 1054 for that model year may certify any such family that contains both nonroad and stationary engines as a single engine family and/or may include any such family containing stationary engines in the averaging, banking and trading provisions applicable for such engines under those parts. This paragraph (b) also applies to equipment or component manufacturers certifying to standards under 40 CFR part 1060.

(c) Manufacturers of engine families certified to 40 CFR part 1048 may meet the labeling requirements referred to in paragraph (a) of this section for stationary SI ICE by either adding a separate label containing the information required in paragraph (a) of this section or by adding the words “and stationary” after the word “nonroad” to the label.

(d) For all engines manufactured on or after January 1, 2011, and for all engines with a maximum engine power greater than 25 HP and less than 130 HP manufactured on or after July 1, 2008, a stationary SI engine manufacturer that certifies an engine family solely to the standards applicable to emergency engines must add a permanent label stating that the engines in that family are for emergency use only. The label must be added according to the labeling requirements specified in 40 CFR 1048.135(b).

(e) All stationary SI engines subject to mandatory certification that do not meet the requirements of this subpart must be labeled and exported according to 40 CFR 1068.230. Manufacturers of stationary engines with a maximum engine power greater than 25 HP that are not certified to standards and other requirements under 40 CFR part 1048 are subject to the labeling provisions of 40 CFR 1048.20 pertaining to excluded stationary engines.

(f) For manufacturers of gaseous-fueled stationary engines required to meet the warranty provisions in 40 CFR 1054.120, we may establish an hour-based warranty period equal to at least the certified emissions life of the engines (in engine operating hours) if we determine that these engines are likely to operate for a number of hours greater than the applicable useful life within 24 months. We will not approve an alternate warranty under this paragraph (f) for nonroad engines. An alternate warranty period approved under this paragraph (f) will be the specified number of engine operating hours or two years, whichever comes first. The engine manufacturer shall request this alternate warranty period in its application for certification or in an earlier submission. We may approve an alternate warranty period for an engine family subject to the following conditions:

- (1) The engines must be equipped with non-resettable hour meters.

(2) The engines must be designed to operate for a number of hours substantially greater than the applicable certified emissions life.

(3) The emission-related warranty for the engines may not be shorter than any published warranty offered by the manufacturer without charge for the engines. Similarly, the emission-related warranty for any component shall not be shorter than any published warranty offered by the manufacturer without charge for that component.

Compliance Requirements for Owners and Operators

§ 60.4243 What are my compliance requirements if I am an owner or operator of a stationary SI internal combustion engine?

(a) If you are an owner or operator of a stationary SI internal combustion engine that is manufactured after July 1, 2008, and must comply with the emission standards specified in § 60.4233(a) through (c), you must comply by purchasing an engine certified to the emission standards in § 60.4231(a) through (c), as applicable, for the same engine class and maximum engine power. In addition, you must meet one of the requirements specified in (a)(1) and (2) of this section.

(1) If you operate and maintain the certified stationary SI internal combustion engine and control device according to the manufacturer's emission-related written instructions, you must keep records of conducted maintenance to demonstrate compliance, but no performance testing is required if you are an owner or operator. You must also meet the requirements as specified in 40 CFR part 1068, subparts A through D, as they apply to you. If you adjust engine settings according to and consistent with the manufacturer's instructions, your stationary SI internal combustion engine will not be considered out of compliance.

(2) If you do not operate and maintain the certified stationary SI internal combustion engine and control device according to the manufacturer's emission-related written instructions, your engine will be considered a non-certified engine, and you must demonstrate compliance according to (a)(2)(i) through (iii) of this section, as appropriate.

(i) If you are an owner or operator of a stationary SI internal combustion engine less than 100 HP, you must keep a maintenance plan and records of conducted maintenance to demonstrate compliance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions, but no performance testing is required if you are an owner or operator.

(ii) If you are an owner or operator of a stationary SI internal combustion engine greater than or equal to 100 HP and less than or equal to 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test within 1 year of engine startup to demonstrate compliance.

(iii) If you are an owner or operator of a stationary SI internal combustion engine greater than 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test within 1 year of engine startup and conduct subsequent performance testing every 8,760 hours or 3 years, whichever comes first, thereafter to demonstrate compliance.

(b) If you are an owner or operator of a stationary SI internal combustion engine and must comply with the emission standards specified in § 60.4233(d) or (e), you must demonstrate compliance according to one of the methods specified in paragraphs (b)(1) and (2) of this section.

(1) Purchasing an engine certified according to procedures specified in this subpart, for the same model year and demonstrating compliance according to one of the methods specified in paragraph (a) of this section.

(2) Purchasing a non-certified engine and demonstrating compliance with the emission standards specified in § 60.4233(d) or (e) and according to the requirements specified in § 60.4244, as applicable, and according to paragraphs (b)(2)(i) and (ii) of this section.

(i) If you are an owner or operator of a stationary SI internal combustion engine greater than 25 HP and less than or equal to 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance.

(ii) If you are an owner or operator of a stationary SI internal combustion engine greater than 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test and conduct subsequent performance testing every 8,760 hours or 3 years, whichever comes first, thereafter to demonstrate compliance.

(c) If you are an owner or operator of a stationary SI internal combustion engine that must comply with the emission standards specified in § 60.4233(f), you must demonstrate compliance according paragraph (b)(2)(i) or (ii) of this section, except that if you comply according to paragraph (b)(2)(i) of this section, you demonstrate that your non-certified engine complies with the emission standards specified in § 60.4233(f).

(d) If you own or operate an emergency stationary ICE, you must operate the emergency stationary ICE according to the requirements in paragraphs (d)(1) through (3) of this section. In order for the engine to be considered an emergency stationary ICE under this subpart, any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (d)(1) through (3), is prohibited. If you do not operate the engine according to the requirements in paragraphs (d)(1) through (3), the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary ICE in emergency situations.

(2) You may operate your emergency stationary ICE for the purpose specified in paragraph (d)(2)(i) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (d)(3) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (d)(2).

(i) Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year.

(ii) [Reserved]

(iii) [Reserved]

(3) Emergency stationary ICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year

for maintenance and testing provided in paragraph (d)(2) of this section. Except as provided in paragraph (d)(3)(i) of this section, the 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator;

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

(ii) [Reserved]

(e) Owners and operators of stationary SI natural gas fired engines may operate their engines using propane for a maximum of 100 hours per year as an alternative fuel solely during emergency operations, but must keep records of such use. If propane is used for more than 100 hours per year in an engine that is not certified to the emission standards when using propane, the owners and operators are required to conduct a performance test to demonstrate compliance with the emission standards of § 60.4233.

(f) If you are an owner or operator of a stationary SI internal combustion engine that is less than or equal to 500 HP and you purchase a non-certified engine or you do not operate and maintain your certified stationary SI internal combustion engine and control device according to the manufacturer's written emission-related instructions, you are required to perform initial performance testing as indicated in this section, but you are not required to conduct subsequent performance testing unless the stationary engine undergoes rebuild, major repair or maintenance. Engine rebuilding means to overhaul an engine or to otherwise perform extensive service on the engine (or on a portion of the engine or engine system). For the purpose of this paragraph (f), perform extensive service means to disassemble the engine (or portion of the engine or engine system), inspect and/or replace many of the parts, and reassemble the engine (or portion of the engine or engine system) in such a manner that significantly increases the service life of the resultant engine.

(g) It is expected that air-to-fuel ratio controllers will be used with the operation of three-way catalysts/non-selective catalytic reduction. The AFR controller must be maintained and operated appropriately in order to ensure proper operation of the engine and control device to minimize emissions at all times.

(h) If you are an owner/operator of an stationary SI internal combustion engine with maximum engine power greater than or equal to 500 HP that is manufactured after July 1, 2007 and before July 1, 2008, and must comply with the emission standards specified in sections 60.4233(b) or (c), you must comply by one of the methods specified in paragraphs (h)(1) through (h)(4) of this section.

- (1) Purchasing an engine certified according to 40 CFR part 1048. The engine must be installed and configured according to the manufacturer's specifications.
 - (2) Keeping records of performance test results for each pollutant for a test conducted on a similar engine. The test must have been conducted using the same methods specified in this subpart and these methods must have been followed correctly.
 - (3) Keeping records of engine manufacturer data indicating compliance with the standards.
 - (4) Keeping records of control device vendor data indicating compliance with the standards.
- (i) If you are an owner or operator of a modified or reconstructed stationary SI internal combustion engine and must comply with the emission standards specified in § 60.4233(f), you must demonstrate compliance according to one of the methods specified in paragraphs (i)(1) or (2) of this section.
- (1) Purchasing, or otherwise owning or operating, an engine certified to the emission standards in § 60.4233(f), as applicable.
 - (2) Conducting a performance test to demonstrate initial compliance with the emission standards according to the requirements specified in § 60.4244. The test must be conducted within 60 days after the engine commences operation after the modification or reconstruction.

Testing Requirements for Owners and Operators

§ 60.4244 What test methods and other procedures must I use if I am an owner or operator of a stationary SI internal combustion engine?

Owners and operators of stationary SI ICE who conduct performance tests must follow the procedures in paragraphs (a) through (f) of this section.

- (a) Each performance test must be conducted within 10 percent of 100 percent peak (or the highest achievable) load and according to the requirements in § 60.8 and under the specific conditions that are specified by Table 2 to this subpart.
- (b) You may not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in § 60.8(c). If your stationary SI internal combustion engine is non-operational, you do not need to startup the engine solely to conduct a performance test; however, you must conduct the performance test immediately upon startup of the engine.
- (c) You must conduct three separate test runs for each performance test required in this section, as specified in § 60.8(f). Each test run must be conducted within 10 percent of 100 percent peak (or the highest achievable) load and last at least 1 hour.
- (d) To determine compliance with the NO_x mass per unit output emission limitation, convert the concentration of NO_x in the engine exhaust using Equation 1 of this section:

$$ER = \frac{C_d \times 1.912 \times 10^{-1} \times Q \times T}{HP - hr} \quad (Eq. 1)$$

Where:

ER = Emission rate of NO_x in g/HP-hr.

C_d = Measured NO_x concentration in parts per million by volume (ppmv).

1.912 × 10⁻³ = Conversion constant for ppm NO_x to grams per standard cubic meter at 20 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour, dry basis.

T = Time of test run, in hours.

HP-hr = Brake work of the engine, horsepower-hour (HP-hr).

(e) To determine compliance with the CO mass per unit output emission limitation, convert the concentration of CO in the engine exhaust using Equation 2 of this section:

$$ER = \frac{C_d \times 1.164 \times 10^{-1} \times Q \times T}{HP - hr} \quad (Eq. 2)$$

Where:

ER = Emission rate of CO in g/HP-hr.

C_d = Measured CO concentration in ppmv.

1.164 × 10⁻³ = Conversion constant for ppm CO to grams per standard cubic meter at 20 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meters per hour, dry basis.

T = Time of test run, in hours.

HP-hr = Brake work of the engine, in HP-hr.

(f) For purposes of this subpart, when calculating emissions of VOC, emissions of formaldehyde should not be included. To determine compliance with the VOC mass per unit output emission limitation, convert the concentration of VOC in the engine exhaust using Equation 3 of this section:

$$ER = \frac{C_d \times 1.833 \times 10^{-1} \times Q \times T}{HP - hr} \quad (Eq. 3)$$

Where:

ER = Emission rate of VOC in g/HP-hr.

C_d = VOC concentration measured as propane in ppmv.

1.833 × 10⁻³ = Conversion constant for ppm VOC measured as propane, to grams per standard cubic meter at 20 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meters per hour, dry basis.

T = Time of test run, in hours.

HP-hr = Brake work of the engine, in HP-hr.

(g) If the owner/operator chooses to measure VOC emissions using either Method 18 of 40 CFR part 60, appendix A, or Method 320 of 40 CFR part 63, appendix A, then it has the option of correcting the measured VOC emissions to account for the potential differences in measured values between these methods and Method 25A. The results from Method 18 and Method 320 can be corrected for response factor differences using Equations 4 and 5 of this section. The corrected VOC concentration can then be placed on a propane basis using Equation 6 of this section.

$$RF_i = \frac{C_{Mi}}{C_{Ai}} \quad (\text{Eq. 4})$$

Where:

RF_i = Response factor of compound i when measured with EPA Method 25A.

C_{Mi} = Measured concentration of compound i in ppmv as carbon.

C_{Ai} = True concentration of compound i in ppmv as carbon.

$$C_{i,corr} = RF_i \times C_{i,meas} \quad (\text{Eq. 5})$$

Where:

$C_{i,corr}$ = Concentration of compound i corrected to the value that would have been measured by EPA Method 25A, ppmv as carbon.

$C_{i,meas}$ = Concentration of compound i measured by EPA Method 320, ppmv as carbon.

$$C_{P_{eq}} = 0.6098 \times C_{i,corr} \quad (\text{Eq. 6})$$

Where:

$C_{P_{eq}}$ = Concentration of compound i in mg of propane equivalent per DSCM.

Notification, Reports, and Records for Owners and Operators

§ 60.4245 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary SI internal combustion engine?

Owners or operators of stationary SI ICE must meet the following notification, reporting and recordkeeping requirements.

- (a) Owners and operators of all stationary SI ICE must keep records of the information in paragraphs (a)(1) through (4) of this section.
 - (1) All notifications submitted to comply with this subpart and all documentation supporting any notification.
 - (2) Maintenance conducted on the engine.
 - (3) If the stationary SI internal combustion engine is a certified engine, documentation from the manufacturer that the engine is certified to meet the emission standards and information as required in 40 CFR parts 1048, 1054, and 1060, as applicable.
 - (4) If the stationary SI internal combustion engine is not a certified engine or is a certified engine operating in a non-certified manner and subject to § 60.4243(a)(2), documentation that the engine meets the emission standards.
- (b) For all stationary SI emergency ICE greater than or equal to 500 HP manufactured on or after July 1, 2010, that do not meet the standards applicable to non-emergency engines, the owner or operator of must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. For all stationary SI

emergency ICE greater than or equal to 130 HP and less than 500 HP manufactured on or after July 1, 2011 that do not meet the standards applicable to non-emergency engines, the owner or operator of must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. For all stationary SI emergency ICE greater than 25 HP and less than 130 HP manufactured on or after July 1, 2008, that do not meet the standards applicable to non-emergency engines, the owner or operator of must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The owner or operator must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation.

(c) Owners and operators of stationary SI ICE greater than or equal to 500 HP that have not been certified by an engine manufacturer to meet the emission standards in § 60.4231 must submit an initial notification as required in § 60.7(a)(1). The notification must include the information in paragraphs (c)(1) through (5) of this section. Beginning on February 26, 2025 submit the notification electronically according to paragraph (g) of this section.

- (1) Name and address of the owner or operator;
- (2) The address of the affected source;
- (3) Engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement;
- (4) Emission control equipment; and
- (5) Fuel used.

(d) Owners and operators of stationary SI ICE that are subject to performance testing must submit a copy of each performance test as conducted in § 60.4244 within 60 days after the test has been completed. Performance test reports using EPA Method 18, EPA Method 320, or ASTM D6348-03 (incorporated by reference—see 40 CFR 60.17) to measure VOC require reporting of all QA/QC data. For Method 18, report results from sections 8.4 and 11.1.1.4; for Method 320, report results from sections 8.6.2, 9.0, and 13.0; and for ASTM D6348-03 report results of all QA/QC procedures in Annexes 1-7. Beginning on February 26, 2025, performance tests must be reported electronically according to paragraph (f) of this section.

(e) If you own or operate an emergency stationary SI ICE with a maximum engine power more than 100 HP that operates for the purpose specified in § 60.4243(d)(3)(i), you must submit an annual report according to the requirements in paragraphs (e)(1) through (3) of this section.

- (1) The report must contain the following information:
 - (i) Company name and address where the engine is located.
 - (ii) Date of the report and beginning and ending dates of the reporting period.
 - (iii) Engine site rating and model year.
 - (iv) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.
 - (v)-(vi) [Reserved]
 - (vii) Hours spent for operation for the purposes specified in § 60.4243(d)(3)(i), including the date, start time, and end time for engine operation for the purposes specified in § 60.4243(d)(3)(i). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.
- (2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

(3) The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (<https://cdx.epa.gov/>). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in § 60.4. Beginning on February 26, 2025, submit annual report electronically according to paragraph (g) of this section.

(f) Beginning on February 26, 2025, within 60 days after the date of completing each performance test, you must submit the results following the procedures specified in paragraph (g) of this section. Data collected using test methods that are supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT website (<https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert>) at the time of the test must be submitted in a file format generated using the EPA's ERT. Alternatively, you may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website. Data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test must be included as an attachment in the ERT or an alternate electronic file.

(g) If you are required to submit notifications or reports following the procedure specified in this paragraph (g), you must submit notifications or reports to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI), which can be accessed through the EPA's Central Data Exchange (CDX) (<https://cdx.epa.gov/>). The EPA will make all the information submitted through CEDRI available to the public without further notice to you. Do not use CEDRI to submit information you claim as CBI. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim for some of the information in the report or notification, you must submit a complete file in the format specified in this subpart, including information claimed to be CBI, to the EPA following the procedures in paragraphs (g)(1) and (2) of this section. Clearly mark the part or all of the information that you claim to be CBI. Information not marked as CBI may be authorized for public release without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. All CBI claims must be asserted at the time of submission. Anything submitted using CEDRI cannot later be claimed CBI. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available. You must submit the same file submitted to the CBI office with the CBI omitted to the EPA via the EPA's CDX as described earlier in this paragraph (g).

(1) The preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol, or other online file sharing services. Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address oaqpscbi@epa.gov, and as described in paragraph (g) of this section, should include clear CBI markings. ERT files should be flagged to the attention of the Group Leader, Measurement Policy Group; all other files should be flagged to the attention of the Stationary Spark Ignition Internal Combustion Engine Sector Lead. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if you do not have your own file sharing service, please email oaqpscbi@epa.gov to request a file transfer link.

(2) If you cannot transmit the file electronically, you may send CBI information through the postal service to the following address: OAQPS Document Control Officer (C404-02), OAQPS, U.S. Environmental Protection Agency, 109 T.W. Alexander Drive, P.O. Box 12055, Research Triangle Park, North Carolina 27711. ERT files should be sent to the attention of the Group Leader, Measurement Policy Group, and all other files should be sent to the attention of the Stationary Spark Ignition Internal Combustion Engine Sector Lead. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

(h) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of EPA system outage for failure to timely comply with that reporting requirement. To assert a claim of EPA system outage, you must meet the requirements outlined in paragraphs (h)(1) through (7) of this section.

- (1) You must have been or will be precluded from accessing CEDRI and submitting a required report within the time prescribed due to an outage of either the EPA's CEDRI or CDX systems.
 - (2) The outage must have occurred within the period of time beginning five business days prior to the date that the submission is due.
 - (3) The outage may be planned or unplanned.
 - (4) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.
 - (5) You must provide to the Administrator a written description identifying:
 - (i) The date(s) and time(s) when CDX or CEDRI was accessed and the system was unavailable;
 - (ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to EPA system outage;
 - (iii) A description of measures taken or to be taken to minimize the delay in reporting; and
 - (iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.
 - (6) The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator.
 - (7) In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved.
- (i) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of force majeure for failure to timely comply with that reporting requirement. To assert a claim of force majeure, you must meet the requirements outlined in paragraphs (i)(1) through (5) of this section.
- (1) You may submit a claim if a force majeure event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning five business days prior to the date the submission is due. For the purposes of this section, a force majeure event is defined as an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents you from complying with the requirement to submit a report electronically within the time period prescribed. Examples of such events are acts of nature (*e.g.*, hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility (*e.g.*, large scale power outage).
 - (2) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.
 - (3) You must provide to the Administrator:
 - (i) A written description of the force majeure event;
 - (ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to the force majeure event;
 - (iii) A description of measures taken or to be taken to minimize the delay in reporting; and
 - (iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(4) The decision to accept the claim of force majeure and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(5) In any circumstance, the reporting must occur as soon as possible after the force majeure event occurs.

(j) Any records required to be maintained by this subpart that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to a delegated air agency or the EPA as part of an on-site compliance evaluation.

General Provisions

§ 60.4246 What General Provisions and confidential information provisions apply to me?

(a) Table 3 to this subpart shows which parts of the General Provisions in §§ 60.1 through 60.19 apply to you.

(b) The provisions of 40 CFR 1068.10 and 1068.11 apply for engine manufacturers. For others, the general confidential business information (CBI) provisions apply as described in 40 CFR part 2.

Mobile Source Provisions

§ 60.4247 What parts of the mobile source provisions apply to me if I am a manufacturer of stationary SI internal combustion engines or a manufacturer of equipment containing such engines?

(a) Manufacturers certifying to emission standards in 40 CFR part 1054 must meet the provisions of 40 CFR part 1054. Note that 40 CFR part 1054, appendix I, describes various provisions that do not apply for engines meeting Phase 1 standards in 40 CFR part 1054. Manufacturers of equipment containing stationary SI internal combustion engines meeting the provisions of 40 CFR part 1054 must meet the provisions of 40 CFR part 1060 to the extent they apply to equipment manufacturers.

(b) Manufacturers required to certify to emission standards in 40 CFR part 1048 must meet the provisions of 40 CFR part 1048. Manufacturers certifying to emission standards in 40 CFR part 1048 pursuant to the voluntary certification program must meet the requirements in Table 4 to this subpart as well as the standards in 40 CFR 1048.101.

(c) For manufacturers of stationary SI internal combustion engines participating in the voluntary certification program and certifying engines to Table 1 to this subpart, Table 4 to this subpart shows which parts of the mobile source provisions in 40 CFR parts 1048, 1065, and 1068 apply to you. Compliance with the deterioration factor provisions under 40 CFR 1048.205(n) and 1048.240 will be required for engines built new on and after January 1, 2010. Prior to January 1, 2010, manufacturers of stationary internal combustion engines participating in the voluntary certification program have the option to develop their own deterioration factors based on an engineering analysis.

Definitions

§ 60.4248 What definitions apply to this subpart?

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

Certified emissions life means the period during which the engine is designed to properly function in terms of reliability and fuel consumption, without being remanufactured, specified as a number of hours of operation or calendar years, whichever comes first. The values for certified emissions life for stationary SI ICE with a maximum engine power less than or equal to 19 KW (25 HP) are given in 40 CFR 1054.107 and 1060.101, as appropriate. The values for certified emissions life for stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) certified to 40 CFR part 1048 are given in 40 CFR 1048.101(g). The certified emissions life for stationary SI ICE with a

maximum engine power greater than 75 KW (100 HP) certified under the voluntary manufacturer certification program of this subpart is 5,000 hours or 7 years, whichever comes first. You may request in your application for certification that we approve a shorter certified emissions life for an engine family. We may approve a shorter certified emissions life, in hours of engine operation but not in years, if we determine that these engines will rarely operate longer than the shorter certified emissions life. If engines identical to those in the engine family have already been produced and are in use, your demonstration must include documentation from such in-use engines. In other cases, your demonstration must include an engineering analysis of information equivalent to such in-use data, such as data from research engines or similar engine models that are already in production. Your demonstration must also include any overhaul interval that you recommend, any mechanical warranty that you offer for the engine or its components, and any relevant customer design specifications. Your demonstration may include any other relevant information. The certified emissions life value may not be shorter than any of the following:

- (1) 1,000 hours of operation.
- (2) Your recommended overhaul interval.
- (3) Your mechanical warranty for the engine.

Certified stationary internal combustion engine means an engine that belongs to an engine family that has a certificate of conformity that complies with the emission standards and requirements in this part, or of 40 CFR part 1048 or 1054, as appropriate.

Combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle combustion turbine, any regenerative/recuperative cycle combustion turbine, the combustion turbine portion of any cogeneration cycle combustion system, or the combustion turbine portion of any combined cycle steam/electric generating system.

Compression ignition means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

Date of manufacture means one of the following things:

- (1) For freshly manufactured engines and modified engines, date of manufacture means the date the engine is originally produced.
- (2) For reconstructed engines, date of manufacture means the date the engine was originally produced, except as specified in paragraph (3) of this definition.
- (3) Reconstructed engines are assigned a new date of manufacture if the fixed capital cost of the new and refurbished components exceeds 75 percent of the fixed capital cost of a comparable entirely new facility. An engine that is produced from a previously used engine block does not retain the date of manufacture of the engine in which the engine block was previously used if the engine is produced using all new components except for the engine block. In these cases, the date of manufacture is the date of reconstruction or the date the new engine is produced.

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is number 2 distillate oil.

Digester gas means any gaseous by-product of wastewater treatment typically formed through the anaerobic decomposition of organic waste materials and composed principally of methane and carbon dioxide (CO₂).

Emergency stationary internal combustion engine means any stationary reciprocating internal combustion engine that meets all of the criteria in paragraphs (1) through (3) of this definition. All emergency stationary ICE must comply

with the requirements specified in § 60.4243(d) in order to be considered emergency stationary ICE. If the engine does not comply with the requirements specified in § 60.4243(d), then it is not considered to be an emergency stationary ICE under this subpart.

(1) The stationary ICE is operated to provide electrical power or mechanical work during an emergency situation. Examples include stationary ICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary ICE used to pump water in the case of fire or flood, etc.

(2) The stationary ICE is operated under limited circumstances for situations not included in paragraph (1) of this definition, as specified in § 60.4243(d).

(3) The stationary ICE operates as part of a financial arrangement with another entity in situations not included in paragraph (1) of this definition only as allowed in § 60.4243(d)(3)(i).

Engine manufacturer means the manufacturer of the engine. See the definition of “manufacturer” in this section.

Four-stroke engine means any type of engine which completes the power cycle in two crankshaft revolutions, with intake and compression strokes in the first revolution and power and exhaust strokes in the second revolution.

Freshly manufactured engine means an engine that has not been placed into service. An engine becomes freshly manufactured when it is originally produced.

Gasoline means any fuel sold in any State for use in motor vehicles and motor vehicle engines, or nonroad or stationary engines, and commonly or commercially known or sold as gasoline.

Installed means the engine is placed and secured at the location where it is intended to be operated.

Landfill gas means a gaseous by-product of the land application of municipal refuse typically formed through the anaerobic decomposition of waste materials and composed principally of methane and CO₂.

Lean burn engine means any two-stroke or four-stroke spark ignited engine that does not meet the definition of a rich burn engine.

Liquefied petroleum gas means any liquefied hydrocarbon gas obtained as a by-product in petroleum refining or natural gas production.

Manufacturer has the meaning given in section 216(1) of the Clean Air Act. In general, this term includes any person who manufactures a stationary engine for sale in the United States or otherwise introduces a new stationary engine into commerce in the United States. This includes importers who import stationary engines for resale.

Maximum engine power means maximum engine power as defined in 40 CFR 1048.801.

Model year means the calendar year in which an engine is manufactured (see “date of manufacture”), except as follows:

(1) Model year means the annual new model production period of the engine manufacturer in which an engine is manufactured (see “date of manufacture”), if the annual new model production period is different than the calendar year and includes January 1 of the calendar year for which the model year is named. It may not begin before January 2 of the previous calendar year and it must end by December 31 of the named calendar year.

(2) For an engine that is converted to a stationary engine after being placed into service as a nonroad or other non-stationary engine, model year means the calendar year or new model production period in which the engine was manufactured (see “date of manufacture”).

Natural gas means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the Earth's surface, of which the principal constituent is methane. Natural gas may be field or pipeline quality.

Other internal combustion engine means any internal combustion engine, except combustion turbines, which is not a reciprocating internal combustion engine or rotary internal combustion engine.

Pipeline-quality natural gas means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions, and which is provided by a supplier through a pipeline. Pipeline-quality natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1,100 British thermal units per standard cubic foot.

Rich burn engine means any four-stroke spark ignited engine where the manufacturer's recommended operating air/fuel ratio divided by the stoichiometric air/fuel ratio at full load conditions is less than or equal to 1.1. Engines originally manufactured as rich burn engines, but modified prior to June 12, 2006, with passive emission control technology for NO_x (such as pre-combustion chambers) will be considered lean burn engines. Also, existing engines where there are no manufacturer's recommendations regarding air/fuel ratio will be considered a rich burn engine if the excess oxygen content of the exhaust at full load conditions is less than or equal to 2 percent.

Rotary internal combustion engine means any internal combustion engine which uses rotary motion to convert heat energy into mechanical work.

Spark ignition means relating to either: a gasoline-fueled engine; or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for compression ignition and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

Stationary internal combustion engine means any internal combustion engine, except combustion turbines, that converts heat energy into mechanical work and is not mobile. Stationary ICE differ from mobile ICE in that a stationary internal combustion engine is not a nonroad engine as defined at 40 CFR 1068.30 (excluding paragraph (2)(ii) of that definition), and is not used to propel a motor vehicle, aircraft, or a vehicle used solely for competition. Stationary ICE include reciprocating ICE, rotary ICE, and other ICE, except combustion turbines.

Stationary internal combustion engine test cell/stand means an engine test cell/stand, as defined in 40 CFR part 63, subpart PPPPP, that tests stationary ICE.

Stoichiometric means the theoretical air-to-fuel ratio required for complete combustion.

Subpart means 40 CFR part 60, subpart JJJJ.

Two-stroke engine means a type of engine which completes the power cycle in single crankshaft revolution by combining the intake and compression operations into one stroke and the power and exhaust operations into a second stroke. This system requires auxiliary scavenging and inherently runs lean of stoichiometric.

Volatile organic compounds means volatile organic compounds as defined in 40 CFR 51.100(s).

Voluntary certification program means an optional engine certification program that manufacturers of stationary SI internal combustion engines with a maximum engine power greater than 19 KW (25 HP) that do not use gasoline and are not rich burn engines that use LPG can choose to participate in to certify their engines to the emission standards in § 60.4231(d) or (e), as applicable.

Table 1 to Subpart JJJJ of Part 60—NO_x, CO, and VOC Emission Standards for Stationary Non-Emergency SI Engines ≥100 HP (Except Gasoline and Rich Burn LPG), Stationary SI Landfill/Digester Gas Engines, and Stationary Emergency Engines >25 HP

Engine type and fuel	Maximum engine power	Manufacture date	Emission standards ^a					
			g/HP-hr			ppmvd at 15% O ₂		
			NO _x	CO	VOC ^d	NO _x	CO	VOC ^d
Non-Emergency SI Natural Gas ^b and Non-Emergency SI Lean Burn LPG ^b	100≤HP<500	7/1/2008	2.0	4.0	1.0	160	540	86
		1/1/2011	1.0	2.0	0.7	82	270	60
Non-Emergency SI Lean Burn Natural Gas and LPG	500≤HP<1,350	1/1/2008	2.0	4.0	1.0	160	540	86
		7/1/2010	1.0	2.0	0.7	82	270	60
Non-Emergency SI Natural Gas and Non-Emergency SI Lean Burn LPG (except lean burn 500≤HP<1,350)	HP≥500	7/1/2007	2.0	4.0	1.0	160	540	86
	HP≥500	7/1/2010	1.0	2.0	0.7	82	270	60
Landfill/Digester Gas (except lean burn 500≤HP<1,350)	HP<500	7/1/2008	3.0	5.0	1.0	220	610	80
		1/1/2011	2.0	5.0	1.0	150	610	80
	HP≥500	7/1/2007	3.0	5.0	1.0	220	610	80
		7/1/2010	2.0	5.0	1.0	150	610	80
Landfill/Digester Gas Lean Burn	500≤HP<1,350	1/1/2008	3.0	5.0	1.0	220	610	80
		7/1/2010	2.0	5.0	1.0	150	610	80
Emergency	25<HP<130	1/1/2009	^c 10	387	N/A	N/A	N/A	N/A
	HP≥130		2.0	4.0	1.0	160	540	86

^a Owners and operators of stationary non-certified SI engines may choose to comply with the emission standards in units of either g/HP-hr or ppmvd at 15 percent O₂.

^b Owners and operators of new or reconstructed non-emergency lean burn SI stationary engines with a site rating of greater than or equal to 250 brake HP located at a major source that are meeting the requirements of 40 CFR part 63, subpart ZZZZ, Table 2a do not have to comply with the CO emission standards of Table 1 of this subpart.

^c The emission standards applicable to emergency engines between 25 HP and 130 HP are in terms of NO_x + HC.

^d For purposes of this subpart, when calculating emissions of volatile organic compounds, emissions of formaldehyde should not be included.

Table 2 to Subpart JJJJ of Part 60—Requirements for Performance Tests

[As stated in § 60.4244, you must comply with the following requirements for performance tests within 10 percent of 100 percent peak (or the highest achievable) load].

For each	Complying with the requirement to	You must	Using	According to the following requirements
1. Stationary SI internal combustion engine demonstrating compliance according to § 60.4244	a. Limit the concentration of NO _x in the stationary SI internal combustion engine exhaust	i. Select the sampling port location and the number/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 <i>and</i> 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 d}	(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	(c) Measurements to determine the exhaust flowrate must be made (1) at the same time as the measurement for NO _x concentration or, alternatively (2) according to the option in Section 11.1.2 of Method 1A of 40 CFR part 60, Appendix A-1, if applicable.
		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, ^e or ASTM Method D6348-03 ^{d e}	(d) 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	(5) Method 7E of 40 CFR part 60, appendix A-4, ASTM Method D6522-00 (Reapproved 2005), ^{a d} Method 320 of 40 CFR part 63, appendix A, ^e or ASTM	(e) Results of this test consist of the average of the three 1-hour or longer runs.

[As stated in § 60.4244, you must comply with the following requirements for performance tests within 10 percent of 100 percent peak (or the highest achievable) load].

For each	Complying with the requirement to	You must	Using	According to the following requirements
		device	Method D6348-03 ^{d e}	
	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 <i>and</i> 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 d}	(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 60, appendix A-1 or Method 19 of 40 CFR part 60, appendix A-7	(c) Measurements to determine the exhaust flowrate must be made (1) at the same time as the measurement for CO concentration or, alternatively (2) according to the option in Section 11.1.2 of Method 1A of 40 CFR part 60, Appendix A-1, if applicable.
		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, ^e or ASTM Method D6348-03 ^{d e}	(d) 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	(5) Method 10 of 40 CFR part 60, appendix A4, ASTM	(e) Results of this test consist of the average of the three 1-hour or longer

[As stated in § 60.4244, you must comply with the following requirements for performance tests within 10 percent of 100 percent peak (or the highest achievable) load].

For each	Complying with the requirement to	You must	Using	According to the following requirements
		internal combustion engine; if using a control device, the sampling site must be located at the outlet of the control device	Method D6522-00 (Reapproved 2005), ^{a d e} Method 320 of 40 CFR part 63, appendix A, ^e or ASTM Method D6348-03 ^{d e}	runs.
	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 <i>and</i> 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 d}	(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 60, appendix A-1 or Method 19 of 40 CFR part 60, appendix A-7	(c) Measurements to determine the exhaust flowrate must be made (1) at the same time as the measurement for VOC concentration or, alternatively (2) according to the option in Section 11.1.2 of Method 1A of 40 CFR part 60, Appendix A-1, if applicable.
		iv. If necessary, measure moisture content of the stationary internal combustion engine	(4) Method 4 of 40 CFR part 60, appendix A-3, Method 320 of 40 CFR part 63, appendix A, ^e or ASTM	(d) Measurements to determine moisture must be made at the same time as the measurement for VOC

[As stated in § 60.4244, you must comply with the following requirements for performance tests within 10 percent of 100 percent peak (or the highest achievable) load].

For each	Complying with the requirement to	You must	Using	According to the following requirements
		exhaust at the sampling port location; and	Method D6348-03 ^{d e}	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 hydrocarbon cutter as described in 40 CFR 1065.265, Method 18 of 40 CFR part 60, appendix A-6, ^{c e} Method 320 of 40 CFR part 63, appendix A, ^e or ASTM Method D6348-03 ^{d e}	(e) 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 O₂ 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 website (<http://www.epa.gov/ttn/emc/prelim/otm11.pdf>).

^d Incorporated by reference; see 40 CFR 60.17.

^e You must meet the requirements in § 60.4245(d).

Table 3 to Subpart JJJJ of Part 60—Applicability of General Provisions to Subpart JJJJ

[As stated in § 60.4246, you must comply with the following applicable General Provisions]

General provisions citation	Subject of citation	Applies to subpart	Explanation
§ 60.1	General applicability of the General Provisions	Yes	
§ 60.2	Definitions	Yes	Additional terms defined in § 60.4248.
§ 60.3	Units and abbreviations	Yes	
§ 60.4	Address	Yes	
§ 60.5	Determination of construction or modification	Yes	
§ 60.6	Review of plans	Yes	

[As stated in § 60.4246, you must comply with the following applicable General Provisions]

General provisions citation	Subject of citation	Applies to subpart	Explanation
§ 60.7	Notification and Recordkeeping	Yes	Except that § 60.7 only applies as specified in § 60.4245.
§ 60.8	Performance tests	Yes	Except that § 60.8 only applies to owners and operators who are subject to performance testing in subpart JJJJ.
§ 60.9	Availability of information	Yes	
§ 60.10	State Authority	Yes	
§ 60.11	Compliance with standards and maintenance requirements	Yes	Requirements are specified in subpart JJJJ.
§ 60.12	Circumvention	Yes	
§ 60.13	Monitoring requirements	No	
§ 60.14	Modification	Yes	
§ 60.15	Reconstruction	Yes	
§ 60.16	Priority list	Yes	
§ 60.17	Incorporations by reference	Yes	
§ 60.18	General control device requirements	No	
§ 60.19	General notification and reporting requirements	Yes	

Table 4 to Subpart JJJJ of Part 60—Applicability of Mobile Source Provisions for Manufacturers Participating in the Voluntary Certification Program and Certifying Stationary SI ICE to Emission Standards in Table 1 of Subpart JJJJ**[As stated in § 60.4247, you must comply with the following applicable mobile source provisions if you are a manufacturer participating in the voluntary certification program and certifying stationary SI ICE to emission standards in Table 1 of subpart JJJJ]**

Mobile source provisions citation	Subject of citation	Applies to subpart	Explanation
1048 subpart A	Overview and Applicability	Yes	
1048 subpart B	Emission Standards and Related Requirements	Yes	Except for the specific sections below.
1048.101	Exhaust Emission Standards	No	
1048.105	Evaporative Emission Standards	No	
1048.110	Diagnosing Malfunctions	No	

[As stated in § 60.4247, you must comply with the following applicable mobile source provisions if you are a manufacturer participating in the voluntary certification program and certifying stationary SI ICE to emission standards in Table 1 of subpart JJJ]

Mobile source provisions citation	Subject of citation	Applies to subpart	Explanation
1048.140	Certifying Blue Sky Series Engines	No	
1048.145	Interim Provisions	No	
1048 subpart C	Certifying Engine Families	Yes	Except for the specific sections below.
1048.205(b)	AECD reporting	Yes	
1048.205(c)	OBD Requirements	No	
1048.205(n)	Deterioration Factors	Yes	Except as indicated in 60.4247(c).
1048.205(p)(1)	Deterioration Factor Discussion	Yes	
1048.205(p)(2)	Liquid Fuels as they require	No	
1048.240(b)(c)(d)	Deterioration Factors	Yes	
1048 subpart D	Testing Production-Line Engines	Yes	
1048 subpart E	Testing In-Use Engines	No	
1048 subpart F	Test Procedures	Yes	
1065.5(a)(4)	Raw sampling (refers reader back to the specific emissions regulation for guidance)	Yes	
1048 subpart G	Compliance Provisions	Yes	
1048 subpart H	Reserved		
1048 subpart I	Definitions and Other Reference Information	Yes	
1048 appendix I and II	Yes		
1065 (all subparts)	Engine Testing Procedures	Yes	Except for the specific section below.
1065.715	Test Fuel Specifications for Natural Gas	No	
1068 (all subparts)	General Compliance Provisions for Nonroad Programs	Yes	Except for the specific sections below.
1068.245	Hardship Provisions for Unusual Circumstances	No	
1068.250	Hardship Provisions for Small-Volume Manufacturers	No	
1068.255	Hardship Provisions for Equipment Manufacturers and Secondary Engine Manufacturers	No	

Appendix D. 40 CFR Part 60, Subpart KKKKa—Standards of Performance for Stationary Combustion Turbines

Introduction

§ 60.4300a What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines that commenced construction, modification, or reconstruction after December 13, 2024.

Applicability

§ 60.4305a Does this subpart apply to my stationary combustion turbine?

- (a) Except as provided for in § 60.4310a, you are subject to this subpart if you own or operate a stationary combustion turbine that commenced construction, modification, or reconstruction after December 13, 2024, and that has a base load rating equal to or greater than 10.7 gigajoules per hour (GJ/h) (10 million British thermal units per hour (MMBtu/h)). Any additional heat input from duct burners used with heat recovery steam generating (HRSG) units or fuel preheaters is not included in the heat input value used to determine the applicability of this subpart to a given stationary combustion turbine. However, this subpart does apply to emissions from any associated HRSG and duct burner(s) that are associated with a combustion turbine subject to this subpart.
- (b) A stationary combustion turbine subject to this subpart is not subject to subpart GG or KKKK of this part.
- (c) Duct burners are not subject to subpart D, Da, Db, or Dc of this part (as applicable) if the duct burner is used with a HRSG unit that is part of a combustion turbine that is subject to this subpart.
- (d) If you own or operate a stationary combustion turbine (including a combined cycle combustion turbine or a CHP combustion turbine) that commenced construction, modification, or reconstruction on or before December 13, 2024, you may submit a written petition to the Administrator requesting that the stationary combustion turbine comply with the applicable requirements for modified units under this subpart as an alternative to complying with subpart GG or KKKK of this part, and with subparts D, Da, Db, and Dc of this part, as applicable. If the Administrator or delegated authority approves the petitioner's request, the affected facility must comply with the requirements for modified units under this subpart unless the stationary combustion turbine is reconstructed or replaced with a new facility in the future.
- (e) If you own or operate a combined cycle combustion turbine or combined heat and power combustion turbine, and changes are made after December 13, 2024, to allow the existing combustion turbine to also operate in simple cycle mode and those changes are determined a modification for NSPS purposes, this subpart shall apply to the combustion turbine only as it operates in simple cycle mode, and not to its existing configuration in combined cycle mode.

§ 60.4310a What stationary combustion turbines are not subject to this subpart?

- (a) An integrated gasification combined cycle electric utility steam generating unit subject to subpart Da of this part is not subject to this subpart.
- (b) A stationary combustion turbine used in a combustion turbine test cell/stand, as defined in § 60.4420a, is not subject to this subpart.
- (c) If any solid fuel is combusted in the HRSG, the HRSG is not subject to this subpart.
- (d) Stationary gas turbines subject to title II of the Clean Air Act are not subject to this subpart.

Emission Standards

§ 60.4315a What pollutants are regulated by this subpart?

The pollutants regulated by this subpart are nitrogen oxide (NO_x) and sulfur dioxide (SO₂).

§ 60.4320a What NO_x emissions standard must I meet?

- (a) Except as provided for in paragraph (c) of this section, for each stationary combustion turbine you must not discharge into the atmosphere from the affected facility any gases that contain an amount of NO_x that exceeds the applicable emissions standard and be in accordance with the requirements specified in paragraph (b) of this section. If you choose to use NO_x CEMS, input-based emission rates and standards are determined on a 4-operating-hour rolling basis and output-based emission rates and standards are determined on a 30-operating-day rolling basis. Mass-based emission rates are determined on both a 4-operating-hour and 12-calendar-month rolling basis.

(b) For the purpose of determining compliance with the applicable emissions standard, you must also meet the requirements specified in paragraphs (b)(1) through (4) of this section, as applicable to your affected facility.

(1) The NO_x emission standard that is applicable to your affected facility shall be determined on an operating-hour basis, unless you elect to use the alternative provided for in paragraph (b)(2) of this section. Determining the hourly NO_x emission standards for your affected facility requires recording hourly data and maintaining records according to the requirements in § 60.4390a. For hours with multiple emission standards, the applicable standard for that hour is determined based on the condition, excluding periods of monitor downtime, that corresponds to the highest emissions standard. For example, if your affected facility operates at 70 percent or less of its base load rating for any portion of the hour, the emission limit(s) in table 1 to this subpart for combustion turbines operating at 70 percent or less of base load rating shall apply for that hour.

(2) As an alternative to the requirements specified in paragraph (b)(1) of this section, you may elect to use the lowest NO_x emission standard that is applicable to your affected facility, as determined using table 1 to this subpart, for the entire required compliance period.

(3) During each operating hour when only natural gas is combusted, you must meet the NO_x emission standard as determined by the applicable size category in table 1 or 2 to this subpart, as applicable, which corresponds to a stationary combustion turbine firing natural gas for that operating hour. During each operating hour when the heat input (based on the HHV of the fuels) of the combustion turbine engine is less than 50 percent natural gas (i.e., 50 percent or greater non-natural gas), as defined in § 60.4420a, at any point during an operating hour, you must meet the NO_x emission standard as determined by the applicable size category in table 1 or 2 to this subpart, as applicable, which corresponds to a stationary combustion turbine firing fuels other than natural gas for that operating hour. During each operating hour when the heat input to the combustion turbine engine is greater than 50 percent natural gas, as defined in § 60.4420a, during an entire operating hour while combusting some portion of non-natural gas fuels, you must meet the NO_x emission standard as determined by prorating the applicable NO_x standards, based on the applicable size category in table 1 or 2 to this subpart, as applicable, by the heat input from each fuel type.

(4) If you have two or more combustion turbine engines share a common stack, are connected to a single electric generator, or share a steam turbine, except as provided for in paragraph (b)(4)(i) of this section, you must monitor the hourly NO_x emissions at the common stack in lieu of monitoring each combustion turbine separately. If you choose to comply with the output-based emissions standard, the hourly gross or net energy output (electric, thermal, or mechanical, as applicable) must be the sum of the hourly loads for the individual affected combustion turbines, and you must express the operating time as "stack operating hours" (as defined in 40 CFR 72.2). If you attain compliance with the most stringent applicable emission standard in table 1 or 2 to this subpart, as applicable, at the common stack, each affected combustion turbine sharing the stack is in compliance.

(i) As an alternative to the requirements in this paragraph (b)(4), you may either:

(A) Monitor each combustion turbine separately by measuring the NO_x emissions prior to mixing in the common stack; or

(B) Apportion the NO_x emissions based on the unit's heat input contribution to the total heat input associated with the common stack and the appropriate F-factors. If you chose to comply with the output-based standard, output from a common steam turbine shall be apportioned based on the heat input to each combustion turbine. You may also elect to develop, demonstrate, and provide information satisfactory to the Administrator on alternate methods to apportion the NO_x emissions. The Administrator may approve such alternate methods for apportioning the NO_x emissions whenever the demonstration ensures accurate estimation of emissions regulated under this part.

(ii) [Reserved]

(c) Stationary combustion turbines that meet at least one of the specifications described in paragraphs (c)(1) through (4) of this section are exempt from the applicable NO_x emission standard in paragraphs (a) and (b) of this section.

- (1) An emergency combustion turbine, as defined in § 60.4420a;
- (2) A stationary combustion turbine that, as determined by the Administrator or delegated authority, is used for the research and development of control techniques and/or efficiency improvements relevant to stationary combustion turbine emissions; or
- (3) A stationary combustion turbine that combusts byproduct fuels for which a facility-specific NO_x emissions standard has been established by the Administrator or delegated authority according to the requirements of paragraphs (c)(3)(i) and (ii) of this section is exempt from the emission limits specified in tables 1 and 2 to this subpart.
 - (i) You may request a facility-specific NO_x emission standard by submitting a written request to the Administrator or delegated authority explaining why your affected facility, when combusting the byproduct fuel, is unable to comply with the applicable NO_x emission standard determined using table 1 or 2 to this subpart.
 - (ii) If the Administrator or delegated authority approves the request, a facility-specific NO_x emissions standard will be established in a manner that the Administrator or delegated authority determines to be consistent with minimizing NO_x emissions.
- (4) Military combustion turbines for use in other than a garrison facility and military combustion turbines installed for use as military training facilities.

(d) You must meet the applicable NO_x emissions standard to your affected facility during all times that the affected facility is operating (including periods of startup, shutdown, and malfunction).

§ 60.4325a What emission limit must I meet for NO_x if my turbine burns both natural gas and distillate oil (or some other combination of fuels)?

You must meet the emission limits specified in table 1 or 2 to this subpart. If your turbine operates below 70 percent of the base load rating at any point during an operating hour, the part load standard is applicable during the entire operating hour. For non-part load operating hours, if your stationary combustion turbine's heat input is greater than or equal to 50 percent fuels other than natural gas at any point during an operating hour, your combustion turbine must meet the corresponding limit for non-natural gas. For non-part load operating hours when your total heat input is greater than 50 percent natural gas while combusting some portion of non-natural gas fuels, you must meet the corresponding emissions standard as determined by prorating the applicable NO_x standards, based on the applicable size category in table 1 or 2 to this subpart, as applicable, by the heat input from each fuel type.

§ 60.4330a What SO₂ emissions standard must I meet?

- (a) Except as provided for in paragraphs (b) through (e) of this section, for each new, modified, or reconstructed stationary combustion turbine you must not cause to be discharged from the affected facility and into the atmosphere any gases that contain an amount of SO₂ exceeding either:
 - (1) 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross energy output; or
 - (2) 26 ng SO₂/J (0.060 lb SO₂/MMBtu) heat input.
- (b) For each new, modified, or reconstructed stationary combustion turbine combusting 50 percent or more low-Btu gas per calendar month based on total heat input (using the HHV of the fuel), you must not cause to be discharged from the affected facility and into the atmosphere any gases that contain an amount of SO₂ exceeding either:
 - (1) 650 milligrams of sulfur per standard cubic meter (mg/scm) (28 grains (gr) of sulfur per 100 standard cubic feet (scf)); or
 - (2) 65 ng SO₂/J (0.15 lb SO₂/MMBtu) heat input.
- (c) For each new, modified, or reconstructed stationary combustion turbine located in a noncontinental area, you must not cause to be discharged from the affected facility and into the atmosphere any gases that contain an amount of SO₂ exceeding either:

(1) 780 ng/J (6.2 lb/MWh) gross energy output; or

(2) 180 ng SO₂/J (0.42 lb SO₂/MMBtu) heat input.

(d) For each new, modified, or reconstructed stationary combustion turbine for which the Administrator determines that the affected facility does not have access to natural gas and that the removal of sulfur compounds from the fuel would cause more environmental harm than benefit, you must not cause to be discharged from the affected facility and into the atmosphere any gases that contain an amount of SO₂ exceeding either:

(1) 780 ng/J (6.2 lb/MWh) gross energy output; or

(2) 180 ng SO₂/J (0.42 lb SO₂/MMBtu) heat input.

(e) A stationary combustion turbine subject to either subpart J or Ja of this part is not subject to the SO₂ performance standards in this subpart.

§ 60.4331a What are the requirements for operating a stationary temporary combustion turbine?

(a) Notwithstanding any other provision of this subpart, you may operate a small- or medium-size stationary combustion turbine (i.e., a combustion turbine with a base load rating less than or equal to 850 MMBtu/h) at a single location for up to 24 consecutive months, so long as you comply with all of the requirements in paragraphs (b) through (e) of this section.

(b) You must meet the NO_x emissions standard for stationary temporary combustion turbines in table 1 to this subpart and the applicable SO₂ emissions standard in § 60.4330a.

(c) Unless you elect to demonstrate compliance through the otherwise-applicable monitoring, recordkeeping, and reporting requirements of this subpart, compliance with the NO_x emissions standard must be demonstrated through maintaining the documentation in paragraphs (c)(1) and (2) of this section on-site:

(1) Each stationary temporary combustion turbine in use at the location has a manufacturer's emissions guarantee at or below the full load NO_x emissions standard in table 1 to this subpart; and

(2) Each such turbine has been performance tested at least once in the prior 5 years as meeting the NO_x emissions standard in table 1 to this subpart.

(d) Unless you elect to demonstrate compliance through the otherwise-applicable monitoring, recordkeeping, and reporting requirements of this subpart, compliance with the SO₂ emissions standard must be demonstrated through complying with the provisions in § 60.4372a.

(e) The conditions in paragraphs (e)(1) through (3) of this section apply in determining whether your stationary combustion turbine qualifies as a stationary temporary combustion turbine.

(1) The turbine may only be located at the same stationary source (or group of stationary sources located within a contiguous area and under common control) for a total period of 24 consecutive months. This is the total period of residence time allowed after the turbine commences operation at the location, regardless of whether the turbine is in operation for the entire 24 consecutive month period.

(2) Any temporary combustion turbine that replaces a temporary combustion turbine at a location and performs the same or similar function will be included in calculating the consecutive time period.

(3) The relocation of a stationary temporary combustion turbine within a single stationary source (or group of stationary sources located within a contiguous area and under common control) while performing the same or similar function (i.e., serving the same electric, mechanical, or thermal load) does not restart the 24-calendar month residence time period.

General Compliance Requirements

§ 60.4333a What are my general requirements for complying with this subpart?

(a) You must operate and maintain your stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times, including during startup, shutdown, and malfunction.

(b) If you own or operate a stationary combustion turbine subject to a NO_x emissions standard in § 60.4320a, you must conduct an initial performance test according to § 60.8 using the applicable methods in § 60.4400a or § 60.4405a. Thereafter, unless you perform continuous monitoring consistent with § 60.4335a, § 60.4340a, or §

60.4345a, you must conduct subsequent performance tests according to the applicable requirements in paragraphs (b)(1) through (6) of this section.

(1) Except as provided for in paragraphs (b)(2) through (5) of this section, you must conduct subsequent performance tests within 12 calendar months of the date that the previous performance test was conducted.

(2) If the NO_x emission result from the most recent performance test is less than or equal to 75 percent of the NO_x emissions standard for the stationary combustion turbine, you may reduce the frequency of subsequent performance tests to 26 calendar months following the date the previous performance test was conducted. If the results of any subsequent performance test exceed 75 percent of the NO_x emissions standard for the stationary combustion turbine, you must resume 14-calendar-month performance testing.

(3) An affected facility that has not operated for the 60 calendar days prior to the due date of a performance test is not required to perform the subsequent performance test until 45 calendar days or 10 operating days, whichever is longer, after the next operating day. The Administrator or delegated authority must be notified of recommencement of operation consistent with § 60.4375a(d).

(4) If you own or operate an affected facility that has operated 168 operating hours or less, either in total or using a particular fuel, since the date on which the previous performance test was conducted, you may request that the otherwise required performance test be postponed until the affected facility has operated more than 168 operating hours, either in total or using a particular fuel, since the date on which the previous performance test was conducted. A request for an extension under this paragraph (b)(4) must be addressed to the relevant air division or office director of the appropriate Regional Office of the U.S. EPA as identified in § 60.4(a) for his or her approval at least 30 calendar days prior to the date on which the performance test is required to be conducted. If a postponement is approved, a performance test must be conducted within 45 calendar days after the day that the facility reaches 168 hours of operation since the date on which the previous performance test was conducted. When the facility has operated more than 168 operating hours since the date on which the previous performance test was conducted, the Administrator or delegated authority must be notified consistent with § 60.4375a(e).

(5) For a facility at which a group consisting of no more than five similar stationary combustion turbines (i.e., same manufacturer and model number) is operated, you may request the use of a custom testing schedule by submitting a written request to the Administrator or delegated authority. The minimum requirements of the custom schedule include the conditions specified in paragraphs (b)(5)(i) through (v) of this section.

(i) Emissions from the most recent performance test for each individual affected facility are 75 percent or less of the applicable standard;

(ii) Each stationary combustion turbine uses the same emissions control technology;

(iii) Each stationary combustion turbine is operated in a similar manner;

(iv) Each stationary combustion turbine and its emissions control equipment are maintained according to the manufacturer's recommended maintenance procedures; and

(v) A performance test is conducted on each affected facility at least once every 5 calendar years.

(6) A stationary combustion turbine subject to a NO_x emissions standard in § 60.4320a that exchanges the combustion turbine engine for an overhauled combustion turbine engine as part of an exchange program, must conduct an initial performance test according to § 60.8 using the applicable methods in § 60.4400a or § 60.4405a. (as applicable).

(c) Except as provided for in paragraph (c)(1) or (2) of this section, for each stationary combustion turbine subject to a NO_x emissions standard in § 60.4320a, you must demonstrate continuous compliance using a continuous emissions monitoring system (CEMS) for measuring NO_x emissions according to the provisions in § 60.4345a. If your stationary combustion turbine is equipped with a NO_x CEMS, those measurements must be used to determine excess emissions.

(1) If your stationary combustion turbine uses water or steam injection but not post-combustion controls to meet the applicable NO_x emissions standard in § 60.4320a, you may elect to demonstrate continuous

compliance using the pounds per million British thermal units (lb/MMBtu) or parts per million (ppm) input-based standard according to the provisions in § 60.4335a.

(2) If your stationary combustion turbine does not use water injection, steam injection, or post-combustion controls to meet the applicable NO_x emissions standard in § 60.4320a, you may elect to demonstrate continuous compliance with an input-based standard according to the provisions in § 60.4340a.

(d) An owner or operator of a stationary combustion turbine subject to an SO₂ emissions standard in § 60.4330a must demonstrate compliance using one of the methods specified in paragraphs (d)(1) through (4) of this section.

(1) Conduct an initial performance test according to § 60.8 and use the applicable methods in § 60.4415a.

Thereafter, you must conduct subsequent performance tests within 12 calendar months following the date the previous performance test was conducted. An affected facility that has not operated for the 60 calendar days prior to the due date of a performance test is not required to perform the subsequent performance test until 45 calendar days after the next operating day;

(2) Conduct an initial performance test according to § 60.8 and use the applicable methods in § 60.4415a.

Thereafter, conduct subsequent fuel sulfur analyses using the applicable methods specified in § 60.4360a and at the frequency specified in § 60.4370a;

(3) Conduct an initial performance test according to § 60.8 and use the applicable methods in § 60.4415a.

Thereafter, maintain records (such as a current, valid purchase contract, tariff sheet, or transportation contract) documenting that total sulfur content for the initial and subsequent fuel combusted in your stationary combustion turbine at all times does not exceed applicable conditions specified in § 60.4370a; or

(4) Conduct an initial performance test according to § 60.8 using the applicable methods in § 60.4415a.

Thereafter, continue to monitor SO₂ emissions using a CEMS according to the requirements specified in § 60.4374a.

(e) If you elect to comply with an input-based standard (lb/MMBtu or ppm) and your affected facility includes use of one or more heat recovery steam generating units, then you must determine compliance with the applicable NO_x and SO₂ emission standards according to the procedures specified in paragraph (e)(1) or (2) of this section as applicable to the heat recovery steam generating unit configuration used for your affected facility.

(1) For a configuration where a single combustion turbine engine is exhausted through the heat recovery steam generating unit, you must measure both the emissions at the exhaust stack for the heat recovery steam generating unit and the fuel flow to the combustion turbine engine and any associated duct burners.

(2) For a configuration where two or more combustion turbine engines are exhausted through a single heat recovery steam generating unit, you must measure both the total emissions at the exhaust stack for the heat recovery steam generating unit and the total fuel flow to each combustion turbine engine and any associated duct burners. The applicable emissions standard for the affected facility is equal to the prorated (by heat input) emissions standards of each of the individual combustion turbine engines that are exhausted through the single heat recovery steam generating unit.

(f) If you elect to comply with an output-based standard (lb/MWh) and your affected facility includes use of one or more heat recovery steam generating units, then you must determine compliance with the applicable NO_x and SO₂ emission standards according to the procedures in paragraph (f)(1), (2), or (3) of this section as applicable to the heat recovery steam generating unit configuration used for your affected facility.

(1) For a configuration where a single combustion turbine engine is exhausted through the heat recovery steam generating unit, you must measure both the emissions at the exhaust stack for the heat recovery steam generating unit and the total electrical, mechanical energy, and useful thermal output of the stationary combustion turbine (as applicable).

(2) For a configuration where two or more combustion turbine engines are exhausted through a single heat recovery steam generating unit, you must measure both the total emissions at the exhaust stack for the heat recovery steam generating unit, and the total electrical, mechanical energy, and useful thermal output of the heat recovery steam generating unit and each combustion turbine engine (as applicable). The applicable

emissions standard for the affected facility is equal to the most stringent emissions standard for any individual combustion turbine engines.

(3) For a configuration where your combustion turbine engines are exhausted through two or more heat recovery steam generating units which serve a common steam turbine or steam header, you must measure both the emissions at the exhaust stack for each heat recovery steam generating unit and the total electrical or mechanical energy output of each combustion turbine engine (as applicable). To determine the net or gross energy output of the steam produced by the heat recovery steam generating unit, you must develop a custom method and provide information, satisfactory to the Administrator or delegated authority, apportioning the net or gross energy output of the steam produced by the heat recovery steam generating units to each of the affected stationary combustion turbines.

(g) If you elect to comply with the mass-based standard, you must demonstrate continuous compliance using either a CEMS for measuring NO_x emissions according to the provisions in § 60.4345a or using the methodology in appendix E to part 75 of this chapter.

Monitoring

§ 60.4335a How do I demonstrate compliance with my NO_x emissions standard without using a NO_x CEMS if I use water or steam injection?

If you qualify and elect to demonstrate continuous compliance according to the provisions of § 60.4333a(c)(1), you must install, calibrate, maintain, and operate a continuous monitoring system to monitor and record the fuel consumption and the water or steam to fuel ratio fired in the combustion turbine engine consistent with the requirements in § 60.4342a. Water or steam only needs to be injected when a fuel is being combusted that requires water or steam injection for compliance with the applicable NO_x emissions standard.

§ 60.4340a How do I demonstrate compliance with my NO_x emissions standard without using a NO_x CEMS if I do not use water or steam injection?

(a) If you qualify and elect to demonstrate continuous compliance according to the provisions of § 60.4333a(c)(2), you must demonstrate compliance with the NO_x emissions standard using one of the methods specified in paragraphs (a)(1) through (3) of this section.

(1) Conduct performance tests according to requirements in § 60.4400a;

(2) Monitor the NO_x emissions rate using the methodology in appendix E to part 75 of this chapter, or the low mass emissions methodology in § 75.19 of this chapter; or

(3) Install, calibrate, maintain, and operate an operating parameter continuous monitoring system according to the requirements specified in paragraph (b) of this section and consistent with the requirements specified in § 60.4342a.

(b) If you opt to demonstrate compliance according to the procedures described in paragraph (a)(3) of this section, continuous operating parameter monitoring must be performed using the methods specified in paragraphs (b)(1) through (4) of this section as applicable to the stationary combustion turbine.

(1) Selection of the operating parameters used to comply with this paragraph (b) must be identified in the performance test report. The selection of operating parameters is subject to the review and approval of the Administrator or delegated authority.

(2) For a lean premix stationary combustion turbine, you must continuously monitor the appropriate parameters to determine whether the unit is operating in low-NO_x mode during periods when low-NO_x operation is required to comply with the applicable emission NO_x standard.

(3) For a stationary combustion turbine other than a lean premix stationary combustion turbine, you must define parameters indicative of the unit's NO_x formation characteristics and monitor these parameters continuously.

(4) You must perform the parametric monitoring described in section 2.3 in appendix E to part 75 of this chapter or in § 75.19(c)(1)(iv)(H) of this chapter.

§ 60.4342a How do I monitor NO_x control operating parameters?

(a) If you monitor steam or water to fuel ratio according to § 60.4335a or other parameters according to § 60.4340a, the applicable parameters must be continuously monitored and recorded during the performance test, to establish acceptable values and ranges. You may supplement the performance test data with engineering analyses, design specifications, manufacturer's recommendations, and other relevant information to define the acceptable parametric ranges more precisely. You must develop and keep on-site a parameter monitoring plan which explains the procedures used to document proper operation of the NO_x emission controls. The plan must include the information specified in paragraphs (a)(1) through (6) of this section:

- (1) Identification of the parameters to be monitored and show there is a significant relationship to emissions and proper operation of the NO_x emission controls;
- (2) Selected parameter ranges (or designated conditions) indicative of proper operation of the stationary combustion turbine NO_x emission controls, or describe the process by which such range (or designated condition) will be established;
- (3) Explanation of the process you will use to make certain that you obtain data that are representative of the emissions or parameters being monitored (such as detector location, installation specification if applicable);
- (4) Description of quality assurance and control practices used to ensure the continuing validity of the data;
- (5) Description of the frequency of monitoring and the data collection procedures which you will use (e.g., you are using a computerized data acquisition over a number of discrete data points with the average (or maximum value) being used for purposes of determining whether an exceedance has occurred); and
- (6) Justification for the proposed elements of the monitoring. If a proposed performance specification differs from manufacturer recommendation, you must explain the reasons for the differences. You must submit the data supporting the justification, but you may refer to generally available sources of information used to support the justification. You may rely on engineering assessments and other data, provided you demonstrate factors which assure compliance or explain why performance testing is unnecessary to establish indicator ranges.

(b) The water or steam to fuel ratio and parameter continuous monitoring system ranges must be confirmed or reestablished at least once every 60 calendar months following the previous calibration and each time the combustion turbine engine is replaced with an overhauled turbine engine as part of an exchange program. An affected facility that has not operated for 60 calendar days prior to the due date of a recalibration or has had the combustion turbine replaced with an overhauled turbine engine as part of an exchange program is not required to perform the subsequent recalibration until 45 calendar days after the next operating day.

§ 60.4345a How do I demonstrate compliance with my NO_x emissions standard using a NO_x CEMS?

(a) Each CEMS measuring NO_x emissions used to meet the requirements of this subpart, must meet the requirements in paragraphs (a)(1) through (6) of this section.

- (1) You must install, certify, maintain, and operate a NO_x monitor to determine the hourly average NO_x emissions in the units of the standard with which you are complying.
- (2) If you elect to comply with an input-based or mass-based emissions standard, you must install, calibrate, maintain, and operate either a fuel flow meter (or flow meters) or an O₂ or CO₂ CEMS and a stack flow monitor to continuously measure the heat input to the affected facility.
- (3) If you elect to comply with an output-based emissions standard, you must also install, calibrate, maintain, and operate both a watt meter (or meters) to continuously measure the gross electrical output from the affected facility and either a fuel flow meter (or flow meters) or an O₂ or CO₂ CEMS and a stack flow monitor. If you have a CHP combustion turbine and elect to comply with an output-based emissions standard, you must also install, calibrate, maintain, and operate meters to continuously determine the total useful recovered thermal energy. For steam this includes flow rate, temperature, and pressure. If you have a direct mechanical drive application and elect to comply with the output-based emissions standard you must submit a plan to the Administrator or delegated authority for approval of how energy output will be determined.
- (4) If you elect to comply with the part-load NO_x emissions standard, you must install, calibrate, maintain, and operate either a fuel flow meter (or flow meters) or an O₂ or CO₂ CEMS and a stack flow monitor to continuously measure the heat input to the affected facility.

(5) If you elect to comply with the temperature dependent NO_x emissions standard, you must install, calibrate, maintain, and operate a thermometer to continuously monitor the ambient temperature.

(6) If you combust natural gas with fuels other than natural gas and elect to comply with the fuels other than natural gas NO_x emissions standard, you must install, calibrate, maintain, and operate a device to continuously monitor when a fuel other than natural gas fuel is combusted in the combustion turbine engine.

(b) Each NO_x CEMS must be installed and certified according to Performance Specification 2 (PS 2) in appendix B to this part. The span value must be 125 percent of the highest applicable standard or highest anticipated hourly NO_x emissions rate. Alternatively, span values determined according to section 2.1.2 in appendix A to part 75 may be used. For stationary combustion turbines that do not use post-combustion technology to reduce emissions of NO_x to comply with the requirements of this subpart, you may use NO_x and diluent CEMS that are installed and certified according to appendix A to part 75 in lieu of Procedure 1 in appendix F to this part and the requirements of § 60.13, except that the relative accuracy test audit (RATA) of the CEMS must be performed on a lb/MMBtu basis. For stationary combustion turbines that use post-combustion technology to reduce emissions of NO_x to comply with the requirements of this subpart, you may use NO_x and diluent CEMS that are installed and certified according to appendix A to part 75 in lieu of Procedure 1 in appendix F to this part and the requirements of § 60.13 with approval from the Administrator or delegated authority, except that the relative accuracy test audit (RATA) of the CEMS must be performed on a lb/MMBtu basis.

(c) During each full operating hour, both the NO_x monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour. For partial operating hours, at least one data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two data points (one in each of two quadrants) are required for each monitor.

(d) Each fuel flow meter must be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, fuel flow meters that meet the installation, certification, and quality assurance requirements in appendix D to part 75 of this chapter are acceptable for use under this subpart.

(e) Each watt meter, steam flow meter, and each pressure or temperature measurement device must be installed, calibrated, maintained, and operated according to manufacturer's instructions.

(f) You must develop, submit to the Administrator or delegated authority for approval, maintain, and adhere to an on-site quality assurance (QA) plan for all of the continuous monitoring equipment you use to comply with this subpart. At a minimum, such a QA plan must address the requirements of § 60.13(d), (e), and (h). For the CEMS and fuel flow meters, the owner or operator of a stationary combustion turbine that does not use post-combustion technology to reduce emissions of NO_x to comply with the requirements of this subpart may, with approval of the Administrator or delegated authority, satisfy the requirements of this paragraph (f) by implementing the QA program and plan described in section 1 in appendix B to part 75 of this chapter in lieu of the requirements in § 60.13(d)(1).

(g) At a minimum, non-out-of-control CEMS hourly averages shall be obtained for 90 percent of all operating hours on a 30-operating-day rolling average basis.

§ 60.4350a How do I use the NO_x CEMS data to determine excess emissions?

(a) If you demonstrate continuous compliance using a CEMS for measuring NO_x emissions, excess emissions are defined as the applicable compliance period for the stationary combustion turbine (either 4-operating-hours, 30-operating-days, or 12-calendar-month), during which the average NO_x emissions from your affected facility measured by the CEMS is greater than the applicable maximum allowable NO_x emissions standard specified in § 60.4320a as determined using the procedures specified in this section that apply to your stationary combustion turbine.

(b) The NO_x CEMS data for each operating hour as measured according to the requirements in § 60.4345a must be used to determine the hourly average NO_x emissions. The hourly average for a given operating hour is the average of all data points for the operating hour. However, for any periods during which the NO_x, diluent, flow, watt, steam

pressure, or steam temperature monitors (as applicable) are out-of-control, the data points are not used in determining the hourly average NO_x emissions. All data points that are not collected during out-of-control periods must be used to determine the hourly average NO_x emissions.

(c) For each operating hour in which an hourly average is obtained, the data acquisition and handling system must calculate and record the hourly average NO_x emissions in units of lb/MMBtu or lbs, as applicable, using the appropriate equation from EPA Method 19 in appendix A-7 to this part. For any hour in which the hourly average O₂ concentration exceeds 19.0 percent O₂ (or the hourly average CO₂ concentration is less than 1.0 percent CO₂), a diluent cap value of 19.0 percent O₂ or 1.0 percent CO₂ (as applicable) may be used in the emission calculations.

(d) Data used to meet the requirements of this subpart shall not include substitute data values derived from the missing data procedures of part 75 of this chapter, nor shall the data be bias adjusted according to the procedures of part 75. For units complying with the 12-calendar-month mass-based standard, emissions for hours of missing data shall be estimated by using the average emissions rate of non-out-of-control hours within ±10 percent of the hour of missing data within the 12-calendar-month period. If non-out-of-control data is not available, the maximum hourly emissions rate during the 12-calendar-month period shall be used.

(e) All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages. However, for any periods during which the flow, watt, steam pressure, or steam temperature monitors (as applicable) are out-of-control, the data points are not used in determining the appropriate hourly average value.

(f) Calculate the hourly average NO_x emissions rate, in units of the emissions standard under § 60.4320a, using lb/MMBtu or ppm for units complying with the input-based standard, using lbs for units complying with the mass-based standard, or lb/MWh or kg/MWh for units complying with the output-based standard:

(1) The gross or net energy output is calculated as the sum of the total electrical and mechanical energy generated by the combustion turbine engine; the additional electrical or mechanical energy (if any) generated by the steam turbine following the heat recovery steam generating unit; the total useful thermal energy output that is not used to generate additional electricity or mechanical output, expressed in equivalent MWh, minus the auxiliary load as calculated using equations 1 and 2 to this paragraph (f)(1):

Equation 1 to Paragraph (f)(1)

$$P = \frac{(Pe)_t}{T} + \frac{(Pe)_c}{T} - Pe_A + P_s + P_o \text{ (Eq. 1)}$$

Where:

P = Gross or net energy output of the stationary combustion turbine system in MWh;

(Pe)_t = Electrical or mechanical energy output of the combustion turbine engine in MWh;

(Pe)_c = Electrical or mechanical energy output (if any) of the steam turbine in MWh;

Pe_A = Electric energy used for any auxiliary loads in MWh (only applicable to owners/operators electing to demonstrate compliance on a net output basis);

P_s = Useful thermal energy of the steam, measured relative to ISO conditions, not used to generate additional electric or mechanical output, in MWh;

P_o = Other useful heat recovery, measured relative to ISO conditions, not used for steam generation or performance enhancement of the stationary combustion turbine; and

T = Electric Transmission and Distribution Factor. Equal to 0.95 for CHP combustion turbine where at least 20.0 percent of the total gross useful energy output consists of electric or direct mechanical output and 20.0 percent of the total gross useful energy output consists of useful thermal output on an annual basis. Equal to 1.0 for all other combustion turbines.

Equation 2 to Paragraph (f)(1)

$$P_s = \frac{Q_m \times H}{3.413 \times 10^6 \text{ Btu/MWh}} \text{ (Eq. 2)}$$

Where:

P_s = Useful thermal energy of the steam, measured relative to ISO conditions, not used to generate additional electric or mechanical output, in MWh;

Q_m = Measured steam flow in lb;

H = Enthalpy of the steam at measured temperature and pressure relative to ISO conditions, in Btu/lb; and
 3.413×10^6 = Conversion factor from Btu to MWh.

(2) For mechanical drive applications complying with the output-based standard, use equation 3 to this paragraph (f)(2):

Equation 3 to Paragraph (f)(2)

$$E = \frac{(\text{NO}_x)_m}{\text{BL} \times \text{AL}} \quad (\text{Eq. 3})$$

Where:

E = NO_x emissions rate in lb/MWh;

$(\text{NO}_x)_m$ = NO_x emissions rate in lb/h;

BL = Manufacturer's base load rating of turbine, in MW; and

AL = Actual load as a percentage of the base load rating.

(g) For each stationary combustion turbine demonstrating compliance on a heat input-based emissions standard, excess NO_x emissions are determined on a 4-operating-hour averaging period basis using the NO_x CEMS data and procedures specified in paragraphs (g)(1) and (2) of this section as applicable to the NO_x emissions standard in table 1 to this subpart.

(1) For each 4-operating-hour period, compute the 4-operating-hour rolling average NO_x emissions as the heat input weighted average of the hourly average of NO_x emissions for a given operating hour and the 3 operating hours preceding that operating hour using the applicable equation in paragraph (g)(2) of this section. Calculate a 4-operating-hour rolling average NO_x emissions rate for any 4-operating-hour period when you have valid CEMS data for at least 3 of those hours (e.g., a valid 4-operating-hour rolling average NO_x emissions rate cannot be calculated if 1 or more continuous monitors was out-of-control for the entire hour for more than 1 hour during the 4-operating-hour period).

(2) If you elect to comply with the applicable heat input-based emissions rate standard, calculate both the 4-operating-hour rolling average NO_x emissions rate and the applicable 4-operating-hour rolling average NO_x emissions standard, calculated using hourly values in table 1 to this subpart, using equation 4 to this paragraph (g)(2).

Equation 4 to Paragraph (g)(2)

$$E = \frac{\sum_{i=1}^4 (E_i \times Q_i)}{\sum_{i=1}^4 Q_i} \quad (\text{Eq. 4})$$

Where:

E = 4-operating-hour rolling average NO_x emissions (lb/MMBtu or ng/J);

E_i = Hourly average NO_x emissions rate or emissions standard for operating hour "i" (lb/MMBtu or ng/J); and

Q_i = Total heat input to stationary combustion turbine for operating hour "i" (MMBtu or J as appropriate).

(h)

(1) For each combustion turbine demonstrating compliance on an output-based standard, you must determine excess emissions on a 30-operating-day rolling average basis. The measured emissions rate is the NO_x emissions measured by the CEMS for a given operating day and the 29 operating days preceding that day. Once each day, calculate a new 30-operating-day average measured emissions rate using all hourly average values based on non-out-of-control NO_x emission data for all operating hours during the previous 30-operating-day operating period. Report any 30-operating-day periods for which you have less than 90 percent data availability as monitor downtime. If you elect to comply with the applicable output-based emissions rate standard, calculate the measured emissions rate using equation 5 to this paragraph (h)(1) and calculate the applicable emissions standard using equation 6 to this paragraph (h)(1). If you elect to comply with the applicable output-based emissions rate standard and determine the heat input on an hourly basis, calculate the 30-operating-day rolling average NO_x emissions rate using equation 5, and determine the applicable 30-operating-day rolling average NO_x emissions standard, calculated using values in table 1 to this subpart, using equation 6. Hours are not subcategorized by load for the purposes of determining the applicable output-based standard. The emissions standard for all hours, regardless of load, is the otherwise applicable full load emissions standard.

Equation 5 to Paragraph (h)(1)

$$E = \frac{\sum_{i=1}^n (E_i \times Q_i)}{\sum_{i=1}^n P_i} \quad (\text{Eq. 5})$$

Where:

E = 30-operating-day average NO_x measured emissions rate combustion turbines (lb/MWh or ng/J);

E_i = Hourly average NO_x emissions rate or emissions standard for non-out-of-control operating hour "i" (lb/MMBtu or ng/J);

Q_i = Total heat input to stationary combustion turbine for non-out-of-control operating hour "i" (MMBtu or J as appropriate);

P_i = Total gross or net energy output from stationary combustion turbine for non-out-of-control operating hour "i" (MWh or J); and

n = Total number of operating non-out-of-control hours in the 30-operating-day period.

Equation 6 to Paragraph (h)(1)

$$E = E_{NG} \times \frac{H_{NG}}{H_T} + E_{non-NG} \times \frac{H_{non-NG}}{H_T} \quad (\text{Eq. 6})$$

E = 30-operating-day rolling NO_x emissions standard (lb/MWh or kg/MWh);

E_{NG} = 30-operating-day emissions standard for natural gas-fired combustion turbines (lb/MWh or kg/MWh);

E_{non-NG} = 30-operating-day emissions standard for non-natural gas-fired combustion turbines (lb/MWh or kg/MWh);

H_{NG} = Hours of operation combusting natural gas during the 30-operating-day period;

H_{non-NG} = Hours of operation combusting non-natural gas fuels during the 30-operating-day period; and

H_T = Total hours of operation during the 30-operating-day period.

(2) If you elect to comply with the applicable output-based emissions rate standard and elect to not determine the heat input on an hourly basis, the applicable 30-operating-day emissions rolling NO_x standard is the most stringent standard applicable to the combustion turbine. The 30-operating-day rolling NO_x emissions rate is

determined as the sum of the hourly emissions divided by the sum of the gross or net output over the 30-operating-day period.

(i) For each combustion turbine demonstrating compliance on a mass-based standard, you must determine excess NO_x emissions on both a rolling 4-operating-hour and rolling 12-calendar-month basis using the NO_x CEMS data and procedures specified in paragraphs (i)(1) through (4) of this section as applicable to the NO_x emissions standard in table 2 to this subpart. In addition, during system emergencies each combustion turbine must determine excess NO_x emissions using the procedures specified in paragraph (i)(5) of this section.

(1) For each 4-operating-hour period, compute the 4-operating-hour rolling NO_x emissions as the sum of the hourly NO_x emissions for a given operating hour and the 3 operating hours preceding that operating hour. Calculate a 4-operating-hour NO_x emissions rate for any 4-operating-hour period when you have valid CEMS data for at least 3 of those hours (e.g., a valid 4-operating-hour rolling NO_x emissions rate cannot be calculated if 1 or more continuous monitors was out-of-control for the entire hour for more than 1 hour during the 4-operating-hour period).

(2) Calculate the applicable 4-operating-hour rolling NO_x emissions standard, calculated using hourly values in table 2 to this subpart, using equation 7 to this paragraph (i)(2).

Equation 7 to Paragraph (i)(2)

$$E = \sum_{i=1}^4 (E_i) \text{ (Eq. 7)}$$

Where:

E = 4-operating-hour rolling NO_x emissions (kg or lbs); and

E_i = Hourly NO_x emissions rate or emissions standard for operating hour “i” (kg or lbs).

(3) For each 12-calendar-month period, compute the 12-calendar-month rolling NO_x emissions as the sum of the hourly NO_x emissions for a given month and the 11 calendar months preceding the calendar month. Emissions during system emergencies are not included when calculating the 12-calendar-month emissions rate.

(4) Calculate the applicable 12-calendar-month rolling NO_x emissions standard, calculated using hourly values in table 2 to this subpart, using equation 8 to this paragraph (i)(4). Heat input during system emergencies is not included when calculating the 12-calendar-month emissions standard.

Equation 8 to Paragraph (i)(4)

$$E = E_{NG} \times \frac{H_{NG}}{H_T} + E_{Non-NG} \times \frac{H_{non-NG}}{H_T} \text{ (Eq. 8)}$$

Where:

E = 12-calendar-month rolling NO_x emissions (tonnes or tons);

E_{NG} = 12-calendar-month emissions standard for natural gas-fired combustion turbines (tonnes or tons);

E_{non-NG} = 12-calendar-month emissions standard for non-natural gas-fired combustion turbines (tonnes or tons);

H_{NG} = Hours of operation combusting natural gas during the 12-calendar-month period;

H_{non-NG} = Hours of operation combusting non-natural gas fuels during the 12-calendar-month period; and

H_T = Total hours of operation during the 12-calendar-month period.

(5) During system emergencies during which the owner or operator elects to not include emissions or heat input in the 12-calendar month calculations, the applicable average natural gas-fired emissions standard is 0.83 lb NO_x/MW-rated output (1.8 lb NO_x/MW-rated output when firing non-natural gas) or the current emissions rate necessary to comply with the 12-calendar month natural gas-fired emissions standard of 0.48 tons NO_x/MW-rated output (0.81 tons NO_x/MW-rated output when firing non-natural gas) whichever is more stringent. For example, if a combustion turbine operated for 4,000 hours during the current 12-calendar month period the applicable average natural gas-fired emissions standard during the system emergency would be 0.24 lb

NO_x/MW-rated output and the applicable average non-natural gas-fired emissions standard during the system emergency would be 0.41 lb NO_x/MW-rated output.

§ 60.4360a How do I use fuel sulfur analysis to determine the total sulfur content of the fuel combusted in my stationary combustion turbine?

(a) If you elect to demonstrate compliance with a SO₂ emissions standard according to § 60.4333a(d)(2), the fuel analyses may be performed either by you, a service contractor retained by you, the fuel vendor, or any other qualified agency as determined by the Administrator or delegated authority using the sampling frequency specified in § 60.4370a.

(b) Representative fuel analysis samples may be collected either by an automatic sampling system or manually. For automatic sampling, follow ASTM D5287-97 (Reapproved 2002) (incorporated by reference, see § 60.17) for gaseous fuels or ASTM D4177-95 (Reapproved 2000) (incorporated by reference, see § 60.17) for liquid fuels. For reference purposes when manually collecting gaseous samples, see Gas Processors Association Standard 2166-17 (incorporated by reference, see § 60.17). For reference purposes when manually collecting liquid samples, see either Gas Processors Association Standard 2174-14 or the procedures for manual pipeline sampling in section 14 of ASTM D4057-95 (Reapproved 2000) (both of which are incorporated by reference, see § 60.17).

(c) Each collected fuel analysis sample must be analyzed for the total sulfur content of the fuel and heating value using the methods specified in paragraph (c)(1) or (2) of this section, as applicable to the fuel type.

(1) For the sulfur content of liquid fuels, ASTM D129-00 (Reapproved 2005), or alternatively D1266-98 (Reapproved 2003), D1552-03, D2622-05, D4294-03, D5453-05, D5623-24, or D7039-24 (all of which are incorporated by reference, see § 60.17). For the heating value of liquid fuels, ASTM D240-19 or D4809-18 (both of which are incorporated by reference, see § 60.17); or

(2) For the sulfur content of gaseous fuels, ASTM D1072-90 (Reapproved 1999), or alternatively D3246-05, D4468-85 (Reapproved 2000), D6667-04, or D5504-20 (all of which are incorporated by reference, see § 60.17). If the total sulfur content of the gaseous fuel during the most recent compliance demonstration was less than half the applicable standard, ASTM D4084-05, D4810-88 (Reapproved 1999), D5504-20, or D6228-98 (Reapproved 2003), or Gas Processors Association Standard 2140-17 or 2377-86 (all of which are incorporated by reference, see § 60.17), which measure the major sulfur compounds, may be used. For the heating value of gaseous fuels, ASTM D1826-94 (Reapproved 2003), or alternatively D3588-98 (Reapproved 2003), D4891-89 (Reapproved 2006), or Gas Processors Association Standard 2172-09 (all of which are incorporated by reference, see § 60.17).

§ 60.4370a How frequently must I determine the fuel sulfur content?

(a) If you are complying with requirements in § 60.4360a, the total sulfur content of all fuels combusted in each stationary combustion turbine subject to an SO₂ emissions standard in § 60.4330a must be determined according to the schedule specified in paragraph (a)(1) or (2) of this section, as applicable to the fuel type, unless you determine a custom schedule for the stationary combustion turbine according to paragraph (b) of this section.

(1) Use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 in appendix D to part 75 of this chapter (i.e., flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank or sampling each delivery prior to combining it with liquid fuel already in the intended storage tank).

(2) If the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel must be determined and recorded once per operating day.

(b) As an alternative to the requirements of paragraph (a) of this section, you may implement custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply using the procedures provided in either paragraph (b)(1) or (2) of this section. Either you or the fuel vendor may perform the sampling. As an alternative to using one of these procedures, you may use a custom schedule that has been substantiated with data and approved by the Administrator or delegated authority as a change in monitoring prior to being used to comply with the applicable standard in § 60.4330a.

(1) You may determine and implement a custom sulfur sampling schedule for your stationary combustion turbine using the procedure specified in paragraphs (b)(1)(i) through (iv) of this section.

(i) Obtain daily total sulfur content measurements for 30 consecutive operating days, using the applicable methods specified in this subpart. Based on the results of the 30 daily samples, the required frequency for subsequent monitoring of the fuel's total sulfur content must be as specified in paragraph (b)(1)(ii), (iii), or (iv) of this section, as applicable.

(ii) If none of the 30 daily measurements of the fuel's total sulfur content exceeds half the applicable standard, subsequent sulfur content monitoring may be performed at 12-month intervals provided the fuel source or supplier does not change. If any of the samples taken at 12-month intervals has a total sulfur content greater than half but less than the applicable standard, follow the procedures in paragraph (b)(1)(iii) of this section. If any measurement exceeds the applicable standard, follow the procedures in paragraph (b)(1)(iv) of this section.

(iii) If at least one of the 30 daily measurements of the fuel's total sulfur content is greater than half but less than the applicable standard, but none exceeds the applicable standard, then:

(A) Collect and analyze a sample every 30 days for 3 months. If any sulfur content measurement exceeds the applicable standard, follow the procedures in paragraph (b)(1)(iv) of this section.

Otherwise, follow the procedures in paragraph (b)(1)(iii)(B) of this section.

(B) Begin monitoring at 6-month intervals for 12 months. If any sulfur content measurement exceeds the applicable standard, follow the procedures in paragraph (b)(1)(iv) of this section. Otherwise, follow the procedures in paragraph (b)(1)(iii)(C) of this section.

(C) Begin monitoring at 12-month intervals. If any sulfur content measurement exceeds the applicable standard, follow the procedures in paragraph (b)(1)(iv) of this section. Otherwise, continue to monitor at this frequency.

(iv) If a sulfur content measurement exceeds the applicable standard, immediately begin daily monitoring according to paragraph (b)(1)(i) of this section. Daily monitoring must continue until 30 consecutive daily samples, each having a sulfur content no greater than the applicable standard, are obtained. At that point, the applicable procedures of paragraph (b)(1)(ii) or (iii) of this section must be followed.

(2) You may use the data collected from the 720-hour sulfur sampling demonstration described in section 2.3.6 in appendix D to part 75 of this chapter to determine and implement a sulfur sampling schedule for your stationary combustion turbine using the procedure specified in paragraphs (b)(2)(i) through (iii) of this section.

(i) If the maximum fuel sulfur content obtained from any of the 720 hourly samples does not exceed half the applicable standard, then the minimum required sampling frequency must be one sample at 12-month intervals.

(ii) If any sample result exceeds half the applicable standard, but none exceeds the applicable standard, follow the provisions of paragraph (b)(1)(iii) of this section.

(iii) If the sulfur content of any of the 720 hourly samples exceeds the applicable standard, follow the provisions of paragraph (b)(1)(iv) of this section.

§ 60.4372a How can I demonstrate compliance with my SO₂ emissions standard using records of the fuel sulfur content?

(a) If you elect to demonstrate compliance with a SO₂ emissions standard according to § 60.4333a(d)(3), you must maintain on-site records (such as a current, valid purchase contract, tariff sheet, or transportation contract) documenting that total sulfur content for the fuel combusted in your stationary combustion turbine at all times does not exceed the conditions specified in paragraph (b) through (e) of this section, as applicable to your stationary combustion turbine.

(b) If your stationary combustion turbine is subject to the SO₂ emissions standard in § 60.4330a(a), then the fuel combusted must have a potential SO₂ emissions rate of 26 ng/J (0.060 lb/MMBtu) heat input or less.

- (c) If your stationary combustion turbine is subject to the SO₂ emissions standard in § 60.4330a(b), then the total sulfur content of the gaseous fuel combusted must be 650 (mg/scm) (28 gr/100 scf).
- (d) If your stationary combustion turbine is subject to the SO₂ emissions standard in § 60.4330a(c) or (d), the total sulfur content of the fuel combusted must be:
- (1) For natural gas, 140 gr/100 scf or less.
 - (2) For fuel oil, 0.40 weight percent (4,000 ppmw) or less.
 - (3) For other fuels, potential SO₂ emissions of 180 ng/J (0.42 lb/MMBtu) heat input or less.
- (e) Representative fuel sampling data following the procedures specified in section 2.3.1.4 or 2.3.2.4 in appendix D to part 75 of this chapter documenting that the fuel meets the part 75 requirements to be considered either pipeline natural gas or natural gas. Your stationary combustion turbine may not cause to be discharged into the atmosphere any gases that contain SO₂ in excess of:
- (1) 110 ng SO₂/J (0.90 lb SO₂/MWh) gross energy output or 26 ng SO₂/J (0.060 lb SO₂/MMBtu) heat input; or
 - (2) 780 ng SO₂/J (6.2 lb SO₂/MWh) gross energy output or 180 ng SO₂/J (0.42 lb SO₂/MMBtu) heat input if your combustion turbine is in a noncontinental area.

§ 60.4374a How do I demonstrate compliance with my SO₂ emissions standard and determine excess emissions using a SO₂ CEMS?

- (a) If you demonstrate continuous compliance using a CEMS for measuring SO₂ emissions, excess emissions are defined as the applicable averaging period, either 4-operating-hour or 30-operating-day, during which the average SO₂ emissions from your stationary combustion turbine measured by the CEMS exceeds the applicable SO₂ emissions standard specified in § 60.4330a as determined using the procedures specified in this section that apply to your stationary combustion turbine.
- (b) You must install, calibrate, maintain, and operate a CEMS for measuring SO₂ concentrations and either O₂ or CO₂ concentrations at the outlet of your stationary combustion turbine, and record the output of the system.
- (c) The 1-hour average SO₂ emissions rate measured by a CEMS must be expressed in ng/J or lb/MMBtu heat input and must be used to calculate the average emissions rate under § 60.4330a.
- (d) You must use the procedures for installation, evaluation, and operation of the CEMS as specified in § 60.13 and paragraphs (d)(1) through (3) of this section.
- (1) Each CEMS must be operated according to the applicable procedures under Performance Specifications 1, 2, and 3 in appendix B to this part;
 - (2) Quarterly accuracy determinations and daily calibration drift tests must be performed according to Procedure 1 in appendix F to this part; and
 - (3) The span value of the SO₂ CEMS at the outlet from the SO₂ control device (or outlet of the stationary combustion turbine if no SO₂ control device is used) must be 125 percent of either the highest applicable standard or highest potential SO₂ emissions rate of the fuel combusted. Alternatively, SO₂ span values determined according to section 2.1.1 in appendix A to part 75 of this chapter may be used.
- (e) If you have installed and certified a SO₂ CEMS that meets the requirements of part 75 of this chapter, the Administrator or delegated authority can approve that only quality assured data from the CEMS must be used to identify excess emissions under this subpart. You must report periods where the missing data substitution procedures in subpart D of part 75 are applied as monitoring system downtime in the excess emissions and monitoring performance report required under § 60.7(c).
- (f) All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.
- (g) Calculate the hourly average SO₂ emissions rate, in units of the emissions standard under § 60.4330a, using lb/MMBtu for units complying with the input-based standard or using equation 1 to paragraph (g)(1) of this section for units complying with the output-based standard:
- (1) For simple cycle operation:
Equation 1 to Paragraph (g)(1)

$$E = \frac{(SO_2)_h \times Q}{P} \quad (\text{Eq. 1})$$

Where:

E = Hourly SO₂ emissions rate, in lb/MWh;

(SO₂)_h = Average hourly SO₂ emissions rate, in lb/MMBtu;

Q = Hourly heat input rate to the stationary combustion turbine, in MMBtu, measured using the fuel flow meter(s), e.g., calculated using Equation D-15a in appendix D to part 75 of this chapter, an O₂ or CO₂ CEMS and a stack flow monitor, or the methodologies in appendix F to part 75 of this chapter; and
P = Gross or net energy output of the stationary combustion turbine in MWh.

(2) The gross or net energy output is calculated as the sum of the total electrical and mechanical energy generated by the stationary combustion turbine; the additional electrical or mechanical energy (if any) generated by the steam turbine following the heat recovery steam generating unit; the total useful thermal energy output that is not used to generate additional electricity or mechanical output, expressed in equivalent MWh, minus the auxiliary load as calculated using equations 2 and 3 to this paragraph (g)(2); and any auxiliary load.

Equation 2 to Paragraph (g)(2)

$$P = \frac{(Pe)_t}{T} + \frac{(Pe)_c}{T} - Pe_A + P_s + P_o \quad (\text{Eq. 2})$$

Where:

P = Gross energy output of the stationary combustion turbine system in MWh;

(Pe)_t = Electrical or mechanical energy output of the stationary combustion turbine in MWh;

(Pe)_c = Electrical or mechanical energy output (if any) of the steam turbine in MWh;

Pe_A = Electric energy used for any auxiliary loads in MWh;

P_s = Useful thermal energy of the steam, measured relative to ISO conditions, not used to generate additional electric or mechanical output, in MWh;

P_o = Other useful heat recovery, measured relative to ISO conditions, not used for steam generation or performance enhancement of the stationary combustion turbine; and

T = Electric Transmission and Distribution Factor. Equal to 0.95 for CHP combustion turbine where at least 20.0 percent of the total gross useful energy output consists of electric or direct mechanical output and 20.0 percent of the total gross useful energy output consists of useful thermal output on an annual basis. Equal to 1.0 for all other combustion turbines.

Equation 3 to Paragraph (g)(2)

$$P_s = \frac{Q_m \times H}{3.413 \times 10^6 \text{ Btu/MWh}} \quad (\text{Eq. 3})$$

Where:

P_s = Useful thermal energy of the steam, measured relative to ISO conditions, not used to generate additional electric or mechanical output, in MWh;

Q_m = Measured steam flow rate in lb;

H = Enthalpy of the steam at measured temperature and pressure relative to ISO conditions, in Btu/lb; and

3.413 × 10⁶ = Conversion factor from Btu to MWh.

(3) For mechanical drive applications complying with the output-based standard, use equation 4 to this paragraph (g)(3):

Equation 4 to Paragraph (g)(3)

$$E = \frac{(\text{SO}_2)_m}{\text{BL} \times \text{AL}} \quad (\text{Eq. 4})$$

Where:

E = SO₂ emissions rate in lb/MWh;

(SO₂)_m = SO₂ emissions rate in lb/h;

BL = Manufacturer's base load rating of turbine, in MW; and

AL = Actual load as a percentage of the base load rating.

(h) For each stationary combustion turbine demonstrating compliance on a heat input-based emissions standard, excess SO₂ emissions are determined on a 4-operating-hour averaging period basis using the SO₂ CEMS data and procedures specified in paragraphs (i)(1) and (2) of this section and as applicable to the SO₂ emission standard.

(1) For each 4-operating-hour period, compute the 4-operating-hour rolling average SO₂ emissions as the heat input weighted average of the hourly average of SO₂ emissions for a given operating hour and the 3 operating hours preceding that operating hour using the applicable equation in paragraph (i)(2) of this section. Calculate a 4-operating-hour rolling average SO₂ emissions rate for any 4-operating-hour period when you have valid CEMS data for at least 3 of those hours (e.g., a valid 4-operating-hour rolling average SO₂ emissions rate cannot be calculated if 1 or more continuous monitors was out-of-control for the entire hour for more than 1 hour during the 4-operating-hour period).

(2) If you elect to comply with the applicable heat input-based emissions rate standard, calculate both the 4-operating-hour rolling average SO₂ emissions rate and the applicable 4-operating-hour rolling average SO₂ emission standard using equation 5 to this paragraph (h)(2).

Equation 5 to Paragraph (h)(2)

$$E = \frac{\sum_{i=1}^4 (E_i \times Q_i)}{\sum_{i=1}^4 Q_i} \quad (\text{Eq. 5})$$

Where:

E = 4-operating-hour rolling average SO₂ emissions (lb/MMBtu or ng/J);

E_i = Hourly average SO₂ emissions rate or emissions standard for operating hour "i" (lb/MMBtu or ng/J);
and

Q_i = Total heat input to stationary combustion turbine for operating hour "i" (MMBtu or J as appropriate).

(i) For each combustion turbine demonstrating compliance on an output-based standard, you must determine excess emissions on a 30-operating-day rolling average basis. The measured emissions rate is the SO₂ emissions measured by the CEMS for a given operating day and the 29 operating days preceding that day. Once each operating day, calculate a new 30-operating-day average measured emissions rate using all hourly average values based on non-out-of-control SO₂ emission data for all operating hours during the previous 30-operating-day operating period. Report any 30-operating-day periods for which you have less than 90 percent data availability as monitor downtime. Calculate both the 30-operating-day rolling average SO₂ emissions rate and the applicable 30-operating-day rolling average SO₂ emissions standard using equation 6 to this paragraph (i).

Equation 6 to Paragraph (i)

$$E = \frac{\sum_{i=1}^n (E_i \times Q_i)}{\sum_{i=1}^n P_i} \quad (\text{Eq. 6})$$

Where:

E = 30-operating-day average SO₂ measured emissions rate (lb/MWh or ng/J);

E_i = Hourly average SO₂ measured emissions rate for non-out-of-control operating hour "i" (lb/MMBtu or ng/J);

Q_i = Total heat input to stationary combustion turbine for non-out-of-control operating hour "i" (MMBtu or J as appropriate);

P_i = Total gross energy output from stationary combustion turbine for non-out-of-control operating hour "i" (MWh or J); and

n = Total number of non-out-of-control operating hours in the 30-operating-day period.

(j) At a minimum, non-out-of-control CEMS hourly averages shall be obtained for 90 percent of all operating hours on a 30-operating-day rolling average basis.

Recordkeeping and Reporting

§ 60.4375a What reports must I submit?

(a) An owner or operator of a stationary combustion turbine that elects to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under this subpart, must submit reports of excess emissions and monitor downtime, according to § 60.7(c). Excess emissions must be reported for all periods of unit operation, including startup, shutdown, and malfunction.

(b) The notification requirements of § 60.8 apply to the initial and subsequent performance tests.

(c) An owner or operator of an affected facility complying with § 60.4333a(b)(3) must notify the Administrator or delegated authority within 15 calendar days after the facility recommences operation.

(d) An owner or operator of an affected facility complying with § 60.4333a(b)(4) must notify the Administrator or delegated authority within 15 calendar days after the facility has operated more than 168 operating hours since the date the previous performance test was required to be conducted.

(e) Within 60 days after the date of completing each performance test or continuous emissions monitoring systems (CEMS) performance evaluation that includes a relative accuracy test audit (RATA), you must submit the results following the procedures specified in paragraph (g) of this section. You must submit the report in a file format generated using the EPA's Electronic Reporting Tool (ERT). Alternatively, you may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website (<https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert>) accompanied by the other information required by § 60.8(f)(2) in PDF format.

(f) You must submit to the Administrator semiannual reports of the following recorded information. Beginning on January 15, 2027, or once the report template for this subpart has been available on the Compliance and Emissions Data Reporting Interface (CEDRI) website (<https://www.epa.gov/electronic-reporting-air-emissions/cedri>) for one year, whichever date is later, submit all subsequent reports using the appropriate electronic report template on the CEDRI website for this subpart and following the procedure specified in paragraph (g) of this section. The date report templates become available will be listed on the CEDRI website. Unless the Administrator or delegated State agency or other authority has approved a different schedule for submission of reports, the report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted.

(g) If you are required to submit notifications or reports following the procedure specified in this paragraph (g), you must submit notifications or reports to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI), which can be accessed through the EPA's Central Data Exchange (CDX) (<https://cdx.epa.gov/>). The EPA will make all

the information submitted through CEDRI available to the public without further notice to you. Do not use CEDRI to submit information you claim as CBI. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim for some of the information in the report or notification, you must submit a complete file in the format specified in this subpart, including information claimed to be CBI, to the EPA following the procedures in paragraphs (g)(1) and (2) of this section. Clearly mark the part or all of the information that you claim to be CBI. Information not marked as CBI may be authorized for public release without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. All CBI claims must be asserted at the time of submission. Anything submitted using CEDRI cannot later be claimed CBI. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available. You must submit the same file submitted to the CBI office with the CBI omitted to the EPA via the EPA's CDX as described earlier in this paragraph (g).

(1) The preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol, or other online file sharing services. Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address oaqps_cbi@epa.gov, and as described above, should include clear CBI markings. ERT files should be flagged to the attention of the Group Leader, Measurement Policy Group; all other files should be flagged to the attention of the Stationary Combustion Turbine Sector Lead. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if you do not have your own file sharing service, please email oaqps_cbi@epa.gov to request a file transfer link.

(2) If you cannot transmit the file electronically, you may send CBI information through the postal service to the following address: U.S. EPA, Attn: OAQPS Document Control Officer, Mail Drop: C404-02, 109 T.W. Alexander Drive, P.O. Box 12055, RTP, NC 27711. In addition to the OAQPS Document Control Officer, ERT files should also be sent to the attention of the Group Leader, Measurement Policy Group, and all other files should also be sent to the attention of the Stationary Combustion Turbine Sector Lead. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

(h) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of EPA system outage for failure to timely comply with that reporting requirement. To assert a claim of EPA system outage, you must meet the requirements outlined in paragraphs (h)(1) through (7) of this section.

(1) You must have been or will be precluded from accessing CEDRI and submitting a required report within the time prescribed due to an outage of either the EPA's CEDRI or CDX systems.

(2) The outage must have occurred within the period of time beginning 5 business days prior to the date that the submission is due.

(3) The outage may be planned or unplanned.

(4) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(5) You must provide to the Administrator a written description identifying:

(i) The date(s) and time(s) when CDX or CEDRI was accessed and the system was unavailable;

(ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to EPA system outage;

(iii) A description of measures taken or to be taken to minimize the delay in reporting; and

(iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(6) The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(7) In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved.

(i) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of force majeure for failure to timely comply with that reporting requirement. To assert a claim of force majeure, you must meet the requirements outlined in paragraphs (i)(1) through (5) of this section.

(1) You may submit a claim if a force majeure event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning 5 business days prior to the date the submission is due. For the purposes of this section, a force majeure event is defined as an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents you from complying with the requirement to submit a report electronically within the time period prescribed. Examples of such events are acts of nature (e.g., hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility (e.g., large scale power outage).

(2) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(3) You must provide to the Administrator:

(i) A written description of the force majeure event;

(ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to the force majeure event;

(iii) A description of measures taken or to be taken to minimize the delay in reporting; and

(iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(4) The decision to accept the claim of force majeure and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(5) In any circumstance, the reporting must occur as soon as possible after the force majeure event occurs.

(j) Any records required to be maintained by this subpart that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to a delegated air agency or the EPA as part of an on-site compliance evaluation.

§ 60.4380a How are NO_x excess emissions and monitor downtime reported?

(a) For a stationary combustion turbine that uses water or steam to fuel ratio monitoring and is subject to the reporting requirements under § 60.4375a(a), periods of excess emissions and monitor downtime must be reported as specified in paragraphs (a)(1) through (3) of this section.

(1) An excess emission that must be reported is any operating hour for which the 4-operating-hour rolling average steam or water to fuel ratio, as measured by the continuous monitoring system, is less than the acceptable steam or water to fuel ratio needed to demonstrate compliance with § 60.4320a, as established during the most recent performance test. Any operating hour during which no water or steam is injected into the turbine when the specific conditions require water or steam injection for NO_x control will also be considered an excess emission.

(2) A period of monitor downtime that must be reported is any operating hour in which water or steam is injected into the turbine, but the parametric data needed to determine the steam or water to fuel ratio are unavailable or out-of-control.

(3) Each report

must include the average steam or water to fuel ratio, average fuel consumption, and the stationary combustion turbine load during each excess emission.

(b) For reports required under § 60.4375a(a), periods of excess emissions and monitor downtime for stationary combustion turbines using a CEMS, excess emissions are reported as specified in paragraphs (b)(1) and (2) of this section.

(1) An excess emission that must be reported is any unit operating period in which the 4-operating-hour average NO_x emissions rate, 30-operating-day rolling average NO_x emissions rate, 4-hour mass-based emissions rate, or

the 12-calendar-month mass-based emissions rate exceeds the applicable emissions standard in § 60.4320a as determined in § 60.4350a.

(2) A period of monitor downtime that must be reported is any operating hour in which the data for any of the following parameters that you use to calculate the emission rate, as applicable, used to determine compliance, are either missing or out-of-control: NO_x concentration, CO₂ or O₂ concentration, stack flow rate, heat input rate, steam flow rate, steam temperature, steam pressure, or megawatts. You are only required to monitor parameters used for compliance purposes.

(c) For reports required under § 60.4375a(a), periods of excess emissions and monitor downtime for stationary combustion turbines using combustion parameters or parameters that document proper operation of the NO_x emission controls excess emissions and monitor downtime are reported as specified in paragraphs (c)(1) and (2) of this section.

(1) Excess emissions that must be reported are each 4-operating-hour rolling average in which any monitored parameter (as averaged over the 4-operating-hour period) does not achieve the target value or is outside the acceptable range defined in the parameter monitoring plan for the unit.

(2) Periods of monitor downtime that must be reported are each operating hour in which any of the required parametric data that are used to calculate the emission rate, as applicable, used to determine compliance, are either not recorded or are out-of-control.

§ 60.4385a How are SO₂ excess emissions and monitor downtime reported?

(a) If you choose the option to monitor the sulfur content of the fuel, excess emissions and monitor downtime are defined as follows:

(1) For samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, excess emissions occur each operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the stationary combustion turbine exceeds the applicable standard and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur standard.

(2) If the option to sample each delivery of fuel oil has been selected, you must immediately switch to one of the other oil sampling options (i.e., daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.05 weight percent, 0.15 weight percent, or 0.40 weight percent as applicable. You must continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and you must evaluate excess emissions according to paragraph (a) of this section. When all of the fuel from the delivery has been combusted, you may resume using the as-delivered sampling option.

(3) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

(b) If you choose the option to maintain records of the fuel sulfur content, excess emissions are defined as any period during which you combust a fuel that you do not have appropriate fuel records or that fuel contains sulfur greater than the applicable standard.

(c) For reports required under § 60.4375a(a), periods of excess emissions and monitor downtime for stationary combustion turbines using a CEMS, excess emissions are reported as specified in paragraphs (c)(1) and (2) of this section.

(1) An excess emission that must be reported is any unit operating period in which the 4-operating-hour or 30-operating-day rolling average SO₂ emissions rate exceeds the applicable emissions standard in § 60.4330a as determined in § 60.4374a.

(2) A period of monitor downtime that must be reported is any operating hour in which the data for any of the following parameters that you use to calculate the emission rate, as applicable, used to determine compliance, are either missing or out-of-control: SO₂ concentration, CO₂ or O₂ concentration, stack flow rate, heat input rate,

steam flow rate, steam temperature, steam pressure, or megawatts. You are only required to monitor parameters used for compliance purposes.

§ 60.4390a What records must I maintain?

- (a) You must maintain records of your information used to demonstrate compliance with this subpart as specified in § 60.7.
- (b) An owner or operator of a stationary combustion turbine that uses the other fuels, part-load, or low temperature NO_x standards in the compliance demonstration must maintain concurrent records of the hourly heat input, percent load, ambient temperature, and emissions data as applicable.
- (c) An owner or operator of a stationary combustion turbine that uses the tuning NO_x standard in the compliance demonstration must identify the hours on which the maintenance was performed and a description of the maintenance.
- (d) An owner or operator of a stationary combustion turbine that demonstrates compliance using the output-based standard must maintain concurrent records of the total gross or net energy output and emissions data.
- (e) An owner or operator of a stationary combustion turbine that demonstrates compliance using the water or steam to fuel ratio or a parameter continuous monitoring system must maintain continuous records of the appropriate parameters.
- (f) An owner or operator of a stationary combustion turbine complying with the fuel-based SO₂ standard must maintain records of the results of all fuel analyses or a current, valid purchase contract, tariff sheet, or transportation contract.

§ 60.4395a When must I submit my reports?

Consistent with § 60.7(c), all reports required under § 60.7(c) must be electronically submitted via CEDRI by the 30th day following the end of each 6-month period.

Performance Tests

§ 60.4400a How do I conduct performance tests to demonstrate compliance with my NO_x emissions standard if I do not have a NO_x CEMS?

- (a) You must conduct the performance test according to the requirements in § 60.8 and paragraphs (b) through (d) of this section.
- (b) You must use the methods in either paragraph (b)(1) or (2) of this section to measure the NO_x concentration for each test run.
 - (1) Measure the NO_x concentration using EPA Method 7E in appendix A-4 to this part, EPA Method 20 in appendix A-7 to this part, EPA Method 320 in appendix A to part 63 of this chapter, or ASTM D6348-12 (Reapproved 2020) (incorporated by reference, see § 60.17). For units complying with the output-based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A-1 to this part, and measure and record the electrical and thermal output from the unit. Then, use equation 1 to this paragraph (b)(1) to calculate the NO_x emissions rate:

Equation 1 to Paragraph (b)(1)

$$E = \frac{1.194 \times 10^{-7} \times (\text{NO}_x)_c \times Q_{\text{std}}}{P} \quad (\text{Eq. 1})$$

Where:

E = NO_x emissions rate, in lb/MWh;

1.194×10^{-7} = Conversion constant, in lb/dscf-ppm;

(NO_x)_c = Average NO_x concentration for the run, in ppm;

Q_{std} = Average stack gas volumetric flow rate, in dscf/h; and

P = Average gross or net electrical and mechanical energy output of the stationary combustion turbine, in MW (for simple cycle operation), for combined cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for CHP operation, the sum of all electrical and mechanical output from

the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation or to enhance the performance of the stationary combustion turbine, in MW, calculated according to § 60.4350a.

(2) Measure the NO_x and diluent gas concentrations using either EPA Method 7E in appendix A-4 to this part and EPA Method 3A in appendix A-2 to this part, or EPA Method 20 in appendix A-7 to this part. In addition, when only natural gas is being combusted ASTM D6522-20 (incorporated by reference, see § 60.17) can be used instead of EPA Method 3A in appendix A-2 to this part or EPA Method 20 in appendix A-7 to this part to determine the oxygen content in the exhaust gas. Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), an O₂ or CO₂ CEMS along with a stack flow monitor, or the methodologies in appendix F to part 75 of this chapter, and for units complying with the output-based standard measure the electrical, mechanical, and thermal output of the unit. Use EPA Method 19 in appendix A-7 to this part to calculate the NO_x emissions rate in lb/MMBtu. Then, use equations 1 and, if necessary, 2 and 3 in § 60.4350a(f) to calculate the NO_x emissions rate in lb/MWh.

(c) You must use the methods in either paragraph (c)(1) or (2) of this section to select the sampling traverse points for NO_x and (if applicable) diluent gas.

(1) You must select the sampling traverse points for NO_x and (if applicable) diluent gas according to EPA Method 20 in appendix A-7 to this part or EPA Method 1 in appendix A-1 to this part (non-particulate procedures) and sampled for equal time intervals. The sampling must be performed with a traversing single-hole probe, or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

(2) As an alternative to paragraph (c)(1) of this section, you may select the sampling traverse points for NO_x and (if applicable) diluent gas according to requirements in paragraphs (c)(2)(i) and (ii) of this section.

(i) You perform a stratification test for NO_x and diluent pursuant to the procedures specified in section 6.5.6.1(a) through (e) in appendix A to part 75 of this chapter.

(ii) Once the stratification sampling is completed, you use the following alternative sample point selection criteria for the performance test specified in paragraphs (c)(2)(ii)(A) through (C) of this section.

(A) If each of the individual traverse point NO_x concentrations is within ±10 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±0.5 percent CO₂ (or O₂) from the mean for all traverse points, then you may use three points (located either 16.7, 50.0 and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall). The three points must be located along the measurement line that exhibited the highest average NO_x concentration during the stratification test; or

(B) For a stationary combustion turbine subject to a NO_x emissions standard greater than 15 ppm at 15 percent O₂, you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO_x concentrations is within ±5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±0.3 percent CO₂ (or O₂) from the mean for all traverse points; or

(C) For a stationary combustion turbine subject to a NO_x emissions standard less than or equal to 15 ppm at 15 percent O₂, you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO_x concentrations is within ±2.5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±0.15 percent CO₂ (or O₂) from the mean for all traverse points.

(d) The performance test must be done at any load condition within ±25 percent of 100 percent of the base load rating. You may perform testing at the highest achievable load point, if at least 75 percent of the base load rating

cannot be achieved in practice. You must conduct three separate test runs for each performance test. The minimum time per run is 20 minutes.

- (1) If the stationary combustion turbine combusts both natural gas and fuels other than natural gas as primary or backup fuels, separate performance testing is required for each fuel.
- (2) For a combined cycle or CHP combustion turbine with supplemental heat (duct burner), you must measure the total NO_x emissions downstream of the duct burner. The duct burner must be in operation within ± 25 percent of 100 percent of the base load rating of the duct burners or the highest achievable load if at least 75 percent of the base load rating of the duct burners cannot be achieved during the performance test.
- (3) If water or steam injection is used to control NO_x with no additional post-combustion NO_x control and you choose to monitor the steam or water to fuel ratio in accordance with § 60.4335a, then that monitoring system must be operated concurrently with each EPA Method 20 in appendix A-7 to this part or EPA Method 7E in appendix A-4 to this part run and must be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable § 60.4320a NO_x emissions standard.
- (4) If you elect to install a CEMS, the performance evaluation of the CEMS may either be conducted separately or (as described in § 60.4405a) as part of the initial performance test of the affected unit.
- (5) The ambient temperature must be greater than 0 °F during the performance test. The Administrator or delegated authority may approve performance testing below 0 °F if the timing of the required performance test and environmental conditions make it impractical to test at ambient conditions greater than 0 °F.

§ 60.4405a How do I conduct a performance test if I use a NO_x CEMS?

- (a) If you use a CEMS the performance test must be performed according to the procedures specified in paragraph (b) of this section.
- (b) The initial performance test must use the procedure specified in paragraphs (b)(1) through (4) of this section.
 - (1) Perform a minimum of nine RATA reference method runs, with a minimum time per run of 21 minutes, at a single load level, within ± 25 percent of 100 percent of the base load rating while the source is combusting the fuel that is a normal primary fuel for that source. You may perform testing at the highest achievable load point, if at least 75 percent of the base load rating cannot be achieved in practice. The ambient temperature must be greater than 0 °F during the RATA runs. The Administrator or delegated authority may approve performance testing below 0 °F if the timing of the required performance test and environmental conditions make it impractical to test at ambient conditions greater than 0 °F.
 - (2) For each RATA run, concurrently measure the heat input to the unit using a fuel flow meter (or flow meters) or the methodologies in appendix F to part 75 of this chapter, and for units complying with the output-based standard, measure the electrical and thermal output from the unit.
 - (3) Use the test data both to demonstrate compliance with the applicable NO_x emissions standard under § 60.4320a and to provide the required reference method data for the RATA of the CEMS described under § 60.4342a.
 - (4) Compliance with the applicable emissions standard in § 60.4320a is achieved if the sum of the NO_x emissions divided by the heat input (or gross or net energy output) for all the RATA runs, expressed in units of lb/MMBtu, ppm, lb/MWh, or kgs, does not exceed the emissions standard.

§ 60.4415a How do I conduct performance tests to demonstrate compliance with my SO₂ emissions standard?

- (a) If you are an owner or operator of an affected facility complying with the fuel-based standard must submit fuel records (such as a current, valid purchase contract, tariff sheet, transportation contract, or results of a fuel analysis) to satisfy the requirements of § 60.8.
- (b) If you are an owner or operator of an affected facility complying with the SO₂ emissions standard must conduct the performance test by measuring the SO₂ emissions in the stationary combustion turbine exhaust gases using the methods in either paragraph (b)(1) or (2) of this section.
 - (1) Measure the SO₂ concentration using EPA Method 6, 6C, or 8 in appendix A-4 to this part or EPA Method 20 in appendix A-7 to this part. For units complying with the output-based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A-1 to this part, and measure and record the

electrical and thermal output from the unit. Then use equation 1 to this paragraph (b)(1) to calculate the SO₂ emissions rate:

Equation 1 to Paragraph (b)(1)

$$E = \frac{1.664 \times 10^{-7} \times (SO_2)_c \times Q_{std}}{P} \quad (\text{Eq. 1})$$

Where:

E = SO₂ emissions rate, in lb/MWh;

1.664×10^{-7} = Conversion constant, in lb/dscf-ppm;

(SO₂)_c = Average SO₂ concentration for the run, in ppm;

Q_{std} = Average stack gas volumetric flow rate, in dscf/h; and

P = Average gross electrical and mechanical energy output of the stationary combustion turbine, in MW (for simple cycle operation), for combined cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for CHP operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation or to enhance the performance of the stationary combustion turbine, in MW, calculated according to § 60.4350a(f)(2).

(2) Measure the SO₂ and diluent gas concentrations, using either EPA Method 6, 6C, or 8 in appendix A-4 to this part and EPA Method 3A in appendix A-2 to this part, or EPA Method 20 in appendix A-7 to this part.

Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), an O₂ or CO₂ CEMS along with a stack flow monitor, or the methodologies in appendix F to part 75 of this chapter, and for units complying with the output based standard measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A-7 to this part to calculate the SO₂ emissions rate in lb/MMBtu. Then, use equations 1 and, if necessary, 2, 3, and 4 in § 60.4374a to calculate the SO₂ emissions rate in lb/MWh.

Other Requirements and Information

§ 60.4416a What parts of the general provisions apply to my affected EGU?

(a) Notwithstanding any other provision of this chapter, certain parts of the general provisions in §§ 60.1 through 60.19, listed in table 2 to this subpart, do not apply to your affected combustion turbine.

(b) Small, medium, and low utilization large combustion turbines that are subject to this subpart and are not a “major source” or located at a “major source” (as that term is defined at 42 U.S.C. 7661(2)) are exempt from the requirements of 42 U.S.C. 7661a(a).

§ 60.4417a Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the EPA, or a delegated authority such as your State, local, or Tribal agency. If the Administrator has delegated authority to your State, local, or Tribal agency, then that agency, (as well as the EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if this subpart is delegated to your State, local, or Tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or Tribal agency, the Administrator retains the authorities listed in paragraphs (b)(1) through (6) of this section and does not transfer them to the State, local, or Tribal agency. In addition, the EPA retains oversight of this subpart and can take enforcement actions, as appropriate.

(1) Approval of alternatives to the emissions standards.

(2) Approval of major alternatives to test methods.

(3) Approval of major alternatives to monitoring.

(4) Approval of major alternatives to recordkeeping and reporting.

(5) Performance test and data reduction waivers under § 60.8(b).

(6) Approval of an alternative to any electronic reporting to the EPA required by this subpart.

§ 60.4420a What definitions apply to this subpart?

As used in this subpart, all terms not defined in this section will have the meaning given them in the Clean Air Act and in subpart A of this part.

Annual capacity factor means the ratio between the actual heat input to a stationary combustion turbine during a calendar year and the potential heat input to the stationary combustion turbine had it been operated for 8,760 hours during a calendar year at the base load rating. Heat input during a system emergency as defined in § 60.4420a is excluded when determining the annual capacity factor. Actual and potential heat input derived from non-combustion sources (e.g., solar thermal) are not included when calculating the annual capacity factor.

Base load rating means 100 percent of the manufacturer's design heat input capacity of the combustion turbine engine at ISO conditions using the higher heating value of the fuel. The base load rating does not include any potential heat input to an HRSG.

Biogas means gas produced by the anaerobic digestion or fermentation of organic matter including manure, sewage sludge, municipal solid waste, biodegradable waste, or any other biodegradable feedstock, under anaerobic conditions. Biogas is comprised primarily of methane and CO₂.

Byproduct means any liquid or gaseous substance produced at chemical manufacturing plants, petroleum refineries, pulp and paper mills, or other industrial facilities (except natural gas and fuel oil).

Combined cycle combustion turbine means any stationary combustion turbine which recovers heat from the combustion turbine engine exhaust gases to generate steam that is used to create additional electric power output in a steam turbine.

Combined heat and power (CHP) combustion turbine means any stationary combustion turbine which recovers heat from the combustion turbine engine exhaust gases to heat water or another medium, generate steam for useful purposes other than exclusively for additional electric generation, or directly uses the heat in the exhaust gases for a useful purpose.

Combustion turbine engine means the air compressor, combustor, and turbine sections of a stationary combustion turbine.

Combustion turbine test cell/stand means any apparatus used for testing uninstalled stationary or uninstalled mobile (motive) combustion turbines.

Diffusion flame stationary combustion turbine means any stationary combustion turbine where fuel and air are injected at the combustor and are mixed only by diffusion prior to ignition.

Distillate oil means fuel oils that comply with the specifications for fuel oil numbers 1 or 2, as defined in ASTM D396-98 (incorporated by reference, see § 60.17), diesel fuel oil numbers 1 or 2, as defined in ASTM D975-08a (incorporated by reference, see § 60.17), kerosene, as defined in ASTM D3699-08 (incorporated by reference, see § 60.17), biodiesel as defined in ASTM D6751-11b (incorporated by reference, see § 60.17), or biodiesel blends as defined in ASTM D7467-10 (incorporated by reference, see § 60.17).

District energy system means a central plant producing hot water, steam, and/or chilled water, which then flows through a network of insulated pipes to provide hot water, space heating, and/or air conditioning for commercial, institutional, or residential buildings.

Dry standard cubic foot (dscf) means the quantity of gas, free of uncombined water, that would occupy a volume of 1 cubic foot at 293 Kelvin (20 °C, 68 °F) and 101.325 kPa (14.69 psi, 1 atm) of pressure.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary combustion turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases.

Emergency combustion turbine means any stationary combustion turbine which operates in an emergency situation. Examples include stationary combustion turbines used to produce power for critical networks or equipment, including power supplied to portions of a facility, when electric power from the local utility is interrupted, or stationary combustion turbines used to pump water in the case of fire (e.g., firefighting turbine) or flood, etc. Emergency combustion turbines may be operated for maintenance checks and readiness testing to retain their status as emergency combustion turbines, provided that the tests are recommended by Federal, State, or local government, agencies, or departments, voluntary consensus standards, the manufacturer, the vendor, the regional

transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the combustion turbine. Required testing of such units should be minimized, but there is no time limit on the use of emergency combustion turbines. Emergency combustion turbines do not include combustion turbines used as peaking units at electric utilities or combustion turbines at industrial facilities that typically operate at low capacity factors.

Excess emissions means a specified averaging period over which either:

- (1) The NO_x or SO₂ emissions rate are higher than the applicable emissions standard in § 60.4320a or § 60.4330a;
- (2) The total sulfur content of the fuel being combusted in the affected facility or the SO₂ emissions exceeds the standard specified in § 60.4330a; or
- (3) The recorded value of a particular monitored parameter, including the water or steam to fuel ratio, is outside the acceptable range specified in the parameter monitoring plan for the affected unit.

Federally enforceable means all limitations and conditions that are enforceable by the Administrator or delegated authority, including the requirements of this part and part 61 of this chapter, requirements within any applicable State Implementation Plan, and any permit requirements established under § 52.21 or §§ CFR 51.18 and 51.24 of this chapter.

Firefighting combustion turbine means any stationary combustion turbine that is used solely to pump water for extinguishing fires.

Fuel oil means a fluid mixture of hydrocarbons that maintains a liquid state at ISO conditions. Additionally, fuel oil must meet the definition of either distillate oil (as defined in this subpart) or liquefied petroleum (LP) gas as defined in ASTM D1835-03a (incorporated by reference, see § 60.17).

Garrison facility means any permanent military installation.

Gross energy output means:

- (1) For simple cycle and combined cycle combustion turbines, the gross useful work performed is the gross electrical or direct mechanical output from both the combustion turbine engine and any associated steam turbine(s).
- (2) For a CHP combustion turbine, the gross useful work performed is the gross electrical or direct mechanical output from both the combustion turbine engine and any associated steam turbine(s) plus any useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (i.e., steam delivered to an industrial process).
- (3) For a CHP combustion turbine where at least 20.0 percent of the total gross useful energy output consists of useful thermal output on an annual basis, the gross useful work performed is the gross electrical or direct mechanical output from both the combustion turbine engine and any associated steam turbine(s) divided by 0.95 plus any useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (i.e., steam delivered to an industrial process).
- (4) For a district energy CHP combustion turbine where at least 20.0 percent of the total gross useful energy output consists of useful thermal output on a 12-calendar-month basis, the gross useful work performed is the gross electrical or direct mechanical output from both the combustion turbine engine and any associated steam turbine(s) divided by 0.95 plus any useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (e.g., steam delivered to an industrial process) divided by 0.95.

Heat recovery steam generating unit (HRSG) means a unit where the hot exhaust gases from the combustion turbine engine are routed in order to extract heat from the gases and generate useful output. Heat recovery steam generating units can be used with or without duct burners. A heat recovery steam generating unit operating independent of the combustion turbine engine may operate burners using ambient air.

High-utilization source means a new medium or large stationary combustion turbine with a 12-calendar-month capacity factor greater than 45 percent.

Integrated gasification combined cycle electric utility steam generating unit (IGCC) means an electric utility steam generating unit that combusts solid-derived fuels in a combined cycle combustion turbine. No solid fuel is directly combusted in the unit during operation.

ISO conditions mean 288 Kelvin (15 °C, 59 °F), 60 percent relative humidity, and 101.325 kilopascals (14.69 psi, 1 atm) pressure.

Large combustion turbine means a stationary combustion turbine with a base load rating greater than 850 MMBtu/h of heat input.

Lean premix stationary combustion turbine means any stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture before delivery to the combustor. Mixing may occur before or in the combustion chamber. A lean premixed turbine may operate in diffusion flame mode during operating conditions such as startup and shutdown, extreme ambient temperature, or low or transient load.

Low-Btu gas means biogas or any gas with a heating value of less than 26 megajoules per standard cubic meter (MJ/scm) (700 Btu/scf).

Low-utilization source means a new medium or large stationary combustion turbine with a 12-calendar-month capacity factor less than or equal to 45 percent.

Medium combustion turbine means a stationary combustion turbine with a base load rating greater than 50 MMBtu/h and less than or equal to 850 MMBtu/h of heat input.

Natural gas means a fluid mixture of hydrocarbons, composed of at least 70 percent methane by volume, that has a gross calorific value between 35 and 41 MJ/scm (950 and 1,100 Btu/scf), and that maintains a gaseous state under ISO conditions. Unless processed to meet this definition of natural gas, natural gas does not include the following gaseous fuels: Landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable CO₂ content or heating value.

Net-electric output means the amount of gross generation the generator(s) produces (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)), as measured at the generator terminals, less the electricity used to operate the plant (i.e., auxiliary loads); such uses include fuel handling equipment, pumps, fans, pollution control equipment, other electricity needs, and transformer losses as measured at the transmission side of the step up transformer (e.g., the point of sale).

Net energy output means:

- (1) The net electric or mechanical output from the affected facility plus 100 percent of the useful thermal output; or
- (2) For CHP facilities, where at least 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-calendar-month rolling average basis, the net electric or mechanical output from the affected turbine divided by 0.95, plus 100 percent of the useful thermal output.
- (3) For district energy CHP facilities, where at least 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-calendar-month rolling average basis, the net electric or mechanical output from the affected turbine divided by 0.95, plus 100 percent of the useful thermal output divided by 0.95.

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, the Northern Mariana Islands, or offshore turbines.

Offshore turbine means a stationary combustion turbine located on a platform or facility in an ocean, territorial sea, the outer continental shelf, or the Great Lakes of North America and stationary combustion turbines located in a coastal management zone and elevated on a platform.

Operating day means a 24-hour period between midnight and the following midnight during which any fuel is combusted at any time in the unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

Operating hour means a clock hour during which any fuel is combusted in the affected unit. If the unit combusts fuel for the entire clock hour, the operating hour is a full operating hour. If the unit combusts fuel for only part of the clock hour, the operating hour is a partial operating hour.

Out-of-control period means any period beginning with the hour corresponding to the completion of a daily calibration error, linearity check, or quality assurance audit that indicates that the instrument is not measuring and recording within the applicable performance specifications and ending with the hour corresponding to the completion of an additional calibration error, linearity check, or quality assurance audit following corrective action that demonstrates that the instrument is measuring and recording within the applicable performance specifications.

Simple cycle combustion turbine means any stationary combustion turbine which does not recover heat from the combustion turbine engine exhaust gases for purposes other than enhancing the performance of the stationary combustion turbine itself.

Small combustion turbine means a stationary combustion turbine with a base load rating less than or equal to 50 MMBtu/h of heat input.

Solid fuel means any fuel that has a definite shape and volume, has no tendency to flow or disperse under moderate stress, and is not liquid or gaseous at ISO conditions. This includes, but is not limited to, coal, biomass, and pulverized solid fuels.

Standard cubic foot (scf) means the quantity of gas that would occupy a volume of 1 cubic foot at 293 Kelvin (20.0 °C, 68 °F) and 101.325 kPa (14.69 psi, 1 atm) of pressure.

Standard cubic meter (scm) means the quantity of gas that would occupy a volume of 1 cubic meter at 293 Kelvin (20.0 °C, 68 °F) and 101.325 kPa (14.69 psi, 1 atm) of pressure.

Stationary combustion turbine means all equipment including, but not limited to, the combustion turbine engine, the fuel, air, lubrication and exhaust gas systems, control systems (except post combustion emissions control equipment), heat recovery system (including heat recovery steam generators and duct burners); steam turbine; fuel compressor and/or pump, any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system; plus any integrated equipment that provides electricity or useful thermal output to the combustion turbine engine (e.g., onsite photovoltaics), heat recovery system, or auxiliary equipment. Stationary means that the combustion turbine is not self-propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability. Portable combustion turbines are excluded from the definition of "stationary combustion turbine," and not regulated under this part, if the turbine meets the definition of "nonroad engine" under title II of the Clean Air Act and applicable regulations and is certified to meet emissions standards promulgated pursuant to title II of the Clean Air Act, along with all related requirements.

System emergency means periods when the Reliability Coordinator has declared an Energy Emergency Alert level 1, 2, or 3, which should follow NERC Reliability Standard EOP-011-2, its successor, or equivalent.

Temporary combustion turbine means a combustion turbine that is intended to and remains at a single stationary source (or group of stationary sources located within a contiguous area and under common control) for 24 consecutive months or less.

Turbine tuning means planned maintenance or parameter performance testing of a combustion turbine engine involving adjustment of the operating configuration to maintain proper combustion dynamics or testing machine operating performance. Turbine tuning is limited to 30 hours annually.

Useful thermal output means the thermal energy made available for use in any heating application (e.g., steam delivered to an industrial process for a heating application, including thermal cooling applications) that is not used for electric generation or mechanical output at the affected facility to directly enhance the performance of the affected facility (e.g., economizer output is not useful thermal output, but thermal energy used to reduce fuel moisture is considered useful thermal output) or to supply energy to a pollution control device at the affected facility (e.g., steam provided to a carbon capture system would not be considered useful thermal output). Useful thermal output for affected facilities with no condensate return (or other thermal energy input to affected facilities) or where measuring the energy in the condensate (or other thermal energy input to the affected facilities) would not meaningfully impact the emission rate calculation is measured against the energy in the thermal output at SATP conditions (e.g. liquid water). Affected facilities with meaningful energy in the condensate return (or other thermal

energy input to the affected facility) must measure the energy in the condensate and subtract that energy relative to SATP conditions from the measured thermal output.

Valid data means quality-assured data generated by continuous monitoring systems that are installed, operated, and maintained according to this part or part 75 of this chapter as applicable. For CEMS maintained according to part 75, the initial certification requirements in § 75.20 and appendix A to part 75 must be met before quality-assured data are reported under this subpart; for on-going quality assurance, the daily, quarterly, and semiannual/annual test requirements in sections 2.1, 2.2, and 2.3 of appendix B to part 75 must be met and the data validation criteria in sections 2.1.5, 2.2.3, and 2.3.2 of appendix B to part 75 must be met. For fuel flow meters maintained according to part 75, the initial certification requirements in section 2.1.5 of appendix D to part 75 must be met before quality-assured data are reported under this subpart (except for qualifying commercial billing meters under section 2.1.4.2 of appendix D to part 75), and for on-going quality assurance, the provisions in section 2.1.6 of appendix D to part 75 apply (except for qualifying commercial billing meters). Any out-of-control data is not considered valid data.

Table 1 to Subpart KKKKa of Part 60—Nitrogen Oxide Emission Standards for Stationary Combustion Turbines

Combustion turbine type	Combustion turbine base load rated heat input (HHV)	Input-based NO _x emission standard ¹	Optional output-based NO _x standard ²
New, firing natural gas with utilization rate >45 percent	>850 MMBtu/h	5 ppm at 15 percent O ₂ or 7.9 ng/J (0.018 lb/MMBtu)	0.054 kg/MWh-gross (0.12 lb/MWh-gross) 0.055 kg/MWh-net (0.12 lb/MWh-net).
New, firing natural gas with utilization rate ≤45 percent and with design efficiency ≥38 percent	>850 MMBtu/h	25 ppm at 15 percent O ₂ or 40 ng/J (0.092 lb/MMBtu)	0.38 kg/MWh-gross (0.83 lb/MWh-gross) 0.39 kg/MWh-net (0.85 lb/MWh-net).
New, firing natural gas with utilization rate ≤45 percent and with design efficiency <38 percent	>850 MMBtu/h	9 ppm at 15 percent O ₂ or 14 ng/J (0.033 lb/MMBtu)	0.17 kg/MWh-gross (0.37 lb/MWh-gross) 0.17 kg/MWh-net (0.38 lb/MWh-net).
New, modified, or reconstructed, firing non-natural gas	>850 MMBtu/h	42 ppm at 15 percent O ₂ or 70 ng/J (0.16 lb/MMBtu)	0.45 kg/MWh-gross (1.0 lb/MWh-gross) 0.46 kg/MWh-net (1.0 lb/MWh-net).
Modified or reconstructed, firing natural gas, at all utilization rates, with design efficiency ≥38 percent	>850 MMBtu/h	25 ppm at 15 percent O ₂ or 40 ng/J (0.092 lb/MMBtu)	0.38 kg/MWh-gross (0.83 lb/MWh-gross) 0.39 kg/MWh-net (0.85 lb/MWh-net).
Modified or reconstructed, firing natural gas, at all utilization rates, with design efficiency <38 percent	>850 MMBtu/h	15 ppm at 15 percent O ₂ or 24 ng/J (0.055 lb/MMBtu)	0.28 kg/MWh-gross (0.62 lb/MWh-gross) 0.29 kg/MWh-net (0.30 lb/MWh-net).
New, firing natural gas, at utilization rate >45 percent	>50 MMBtu/h and ≤850 MMBtu/h	15 ppm at 15 percent O ₂ or 24 ng/J (0.055 lb/MMBtu)	0.20 kg/MWh-gross (0.43 lb/MWh-gross) 0.20 kg/MWh-net (0.44 lb/MWh-net).
New, firing natural gas, at utilization rate ≤45 percent	>50 MMBtu/h and ≤850 MMBtu/h	25 ppm at 15 percent O ₂ or 40 ng/J (0.092 lb/MMBtu)	0.54 kg/MWh-gross (1.2 lb/MWh-gross) 0.56 kg/MWh-net (1.2 lb/MWh-net).

Combustion turbine type	Combustion turbine base load rated heat input (HHV)	Input-based NO _x emission standard ¹	Optional output-based NO _x standard ²
Modified or reconstructed, firing natural gas	>20 MMBtu/h and ≤850 MMBtu/h	42 ppm at 15 percent O ₂ or 67 ng/J (0.15 lb/MMBtu)	0.91 kg/MWh-gross (2.0 lb/MWh-gross) 0.92 kg/MWh-net (2.0 lb/MWh-net).
New, firing non-natural gas	>50 MMBtu/h and ≤850 MMBtu/h	74 ppm at 15 percent O ₂ or 120 ng/J (0.29 lb/MMBtu)	1.6 kg/MWh-gross (3.6 lb/MWh-gross) 1.6 kg/MWh-net (3.7 lb/MWh-net).
Modified or reconstructed, firing non-natural gas	>20 MMBtu/h and ≤850 MMBtu/h	96 ppm at 15 percent O ₂ or 160 ng/J (0.37 lb/MMBtu)	2.1 kg/MWh-gross (4.7 lb/MWh-gross) 2.2 kg/MWh-net (4.8 lb/MWh-net).
New, firing natural gas	≤50 MMBtu/h	25 ppm at 15 percent O ₂ or 40 ng/J (0.092 lb/MMBtu)	0.64 kg/MWh-gross (1.4 lb/MWh-gross) 0.65 kg/MWh-net (1.4 lb/MWh-net).
New, firing non-natural gas	≤50 MMBtu/h	96 ppm at 15 percent O ₂ or 160 ng/J (0.37 lb/MMBtu)	2.4 kg/MWh-gross (5.3 lb/MWh-gross) 2.5 kg/MWh-net (5.4 lb/MWh-net).
Modified or reconstructed, all fuels	≤20 MMBtu/h	150 ppm at 15 percent O ₂ or 240 ng/J (0.55 lb/MMBtu)	3.9 kg/MWh-gross (8.7 lb/MWh-gross) 4.0 kg/MWh-net (8.9 lb/MWh-net).
New, firing natural gas, either offshore turbines, turbines bypassing the heat recovery unit, and/or temporary turbines	>50 MMBtu/h	25 ppm at 15 percent O ₂ or 40 ng/J (0.092 lb/MMBtu)	N/A.
Located north of the Arctic Circle (latitude 66.5 degrees north), operating at ambient temperatures less than 0 °F (−18 °C), modified or reconstructed offshore turbines, operated during periods of turbine tuning, byproduct-fired turbines, and/or operating at less than 70 percent of the base load rating	≤300 MMBtu/h	150 ppm at 15 percent O ₂ or 240 ng/J) 0.55 lb/MMBtu	N/A.
Located north of the Arctic Circle (latitude 66.5 degrees north), operating at ambient temperatures less than 0 °F (−18 °C), modified or reconstructed offshore turbines, operated during periods of turbine tuning, byproduct-fired turbines, and/or operating at less than 70 percent of the base load rating	>300 MMBtu/h	96 ppm at 15 percent O ₂ or 150 ng/J (0.35 lb/MMBtu)	N/A.
Heat recovery units operating independent of the combustion turbine	All sizes	54 ppm at 15 percent O ₂ or 86 ng/J) 0.20 lb/MMBtu	N/A.

¹ Input-based standards are determined on a 4-operating-hour rolling average basis.

² Output-based standards are determined on a 30-operating-day average basis.

Table 2 to Subpart KKKKa of Part 60—Alternative Mass-Based NO_x Emission Standards for Stationary Combustion Turbines

Combustion turbine type	4-Hour emissions rate (lb NO _x /MW-rated output)	12-Calendar-month emissions rate (ton NO _x /MW-rated output)
Natural Gas	0.38 kg NO _x /MW-rated output (0.83 lb NO _x /MW-rated output)	0.44 tonne NO _x /MW-rated output (0.48 ton NO _x /MW-rated output).
Non-Natural Gas	0.82 kg NO _x /MW-rated output (1.8 lb NO _x /MW-rated output)	0.74 tonne NO _x /MW-rated output (0.81 ton NO _x /MW-rated output).

Table 3 to Subpart KKKKa of Part 60—Applicability of Subpart A of This Part to This Subpart

General provisions citation	Subject of citation	Applies to subpart KKKKa	Explanation
§ 60.1	Applicability	Yes	
§ 60.2	Definitions	Yes	Additional terms defined in § 60.4420a.
§ 60.3	Units and Abbreviations	Yes	
§ 60.4	Address	Yes	Does not apply to information reported electronically through ECMPS. Duplicate submittals are not required.
§ 60.5	Determination of construction or modification	Yes	
§ 60.6	Review of plans	Yes	
§ 60.7	Notification and Recordkeeping	Yes	Only the requirements to submit the notifications in § 60.7(a)(1) and (3) and to keep records of malfunctions in § 60.7(b), if applicable.
§ 60.8(a)	Performance tests	Yes	
§ 60.8(b)	Performance test method alternatives	Yes	Administrator can approve alternate methods.
§ 60.8(c)	Conducting performance tests	No	Overridden by § 60.4320a(d).
§ 60.8(d)-(f)	Conducting performance tests	Yes	
§ 60.9	Availability of Information	Yes	
§ 60.10	State authority	Yes	
§ 60.11	Compliance with standards and maintenance requirements	No	
§ 60.12	Circumvention	Yes	
§ 60.13(a)-(h), (j)	Monitoring requirements	Yes	
§ 60.13(i)	Monitoring requirements	Yes	Administrator can approve alternative monitoring procedures or requirements.
§ 60.14	Modification	Yes	
§ 60.15	Reconstruction	Yes	
§ 60.16	Priority list	No	
§ 60.17	Incorporations by reference	Yes	
§ 60.18	General control device requirements	Yes	
§ 60.19	General notification and reporting requirements	Yes	Does not apply to notifications under § 75.61 of this chapter or to information reported through ECMPS.

Appendix E. Subpart OOOOb—Standards of Performance for Crude Oil and Natural Gas Facilities for Which Construction, Modification or Reconstruction Commenced After December 6, 2022

§ 60.5360b What is the purpose of this subpart?

(a) *Scope.* This subpart establishes emission standards and compliance schedules for the control of the pollutant greenhouse gases (GHG). The greenhouse gas standard in this subpart is in the form of a limitation on emissions of methane from affected facilities in the crude oil and natural gas source category that commence construction, modification, or reconstruction after December 6, 2022. This subpart also establishes emission standards and compliance schedules for the control of volatile organic compounds (VOC) and sulfur dioxide (SO₂) emissions from affected facilities in the crude oil and natural gas source category that commence construction, modification, or reconstruction after December 6, 2022.

(b) *Prevention of Significant Deterioration (PSD) and title V thresholds for Greenhouse Gases.*

(1) For the purposes of 40 CFR 51.166(b)(49)(ii), with respect to GHG emissions from affected facilities, the “pollutant that is subject to the standard promulgated under section 111 of the Act” shall be considered the pollutant that otherwise is subject to regulation under the Act as defined in 40 CFR 51.166(b)(48) and in any State Implementation Plan (SIP) approved by the EPA that is interpreted to incorporate, or specifically incorporates, 40 CFR 51.166(b)(48).

(2) For the purposes of 40 CFR 52.21(b)(50)(ii), with respect to GHG emissions from affected facilities, the “pollutant that is subject to the standard promulgated under section 111 of the Act” shall be considered the pollutant that otherwise is subject to regulation under the Clean Air Act as defined in 40 CFR 52.21(b)(49).

(3) For the purposes of 40 CFR 70.2, with respect to GHG emissions from affected facilities, the “pollutant that is subject to any standard promulgated under section 111 of the Act” shall be considered the pollutant that otherwise is “subject to regulation” as defined in 40 CFR 70.2.

(4) For the purposes of 40 CFR 71.2, with respect to GHG emissions from affected facilities, the “pollutant that is subject to any standard promulgated under section 111 of the Act” shall be considered the pollutant that otherwise is “subject to regulation” as defined in 40 CFR 71.2.

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

§ 60.5365b Am I subject to this subpart?

You are subject to the applicable provisions of this subpart if you are the owner or operator of one or more of the onshore affected facilities listed in paragraphs (a) through (i) of this section, that is located within the Crude Oil and Natural Gas source category, as defined in § 60.5430b, for which you commence construction, modification, or reconstruction after December 6, 2022. Facilities located inside and including the Local Distribution Company (LDC) custody transfer station are not subject to this subpart.

(a) Each well affected facility, which is a single well drilled for the purpose of producing oil or natural gas.

(1) In addition to § 60.14, a “modification” of an existing well occurs when:

- (i) An existing well is hydraulically fractured, or
- (ii) An existing well is hydraulically refractured.

(2) For the purposes of a well affected facility, a liquids unloading event is not considered to be a modification.

(3) Except as provided in § 60.5365b(e)(3)(ii)(C) and (i)(3)(ii), any action described by paragraphs (a)(1)(i) and (ii) of this section, by itself, does not affect the modification status of process unit equipment, centrifugal or reciprocating compressors, pumps, or process controllers.

(b) Each centrifugal compressor affected facility, which is a single centrifugal compressor. A centrifugal compressor located at a well site is not an affected facility under this subpart. A centrifugal compressor located at a centralized production facility is an affected facility under this subpart.

(c) Each reciprocating compressor affected facility, which is a single reciprocating compressor. A reciprocating compressor located at a well site is not an affected facility under this subpart. A reciprocating compressor located at a centralized production facility is an affected facility under this subpart.

(d) Each process controller affected facility, which is the collection of natural gas-driven process controllers at a well site, centralized production facility, onshore natural gas processing plant, or a compressor station. Natural gas-driven process controllers that function as emergency shutdown devices and process controllers that are not driven by natural gas are not included in the affected facility.

(1) For the purposes of § 60.5390b, in addition to the definition in § 60.14, a modification occurs when the number of natural gas-driven process controllers in the affected facility is increased by one or more.

(2) For the purposes of § 60.5390b, owners and operators may choose to apply reconstruction as defined in § 60.15(b) based on the fixed capital cost of the new process controllers in accordance with paragraph (d)(2)(i) of this section, or the definition of reconstruction based on the number of natural gas-driven process controllers in the affected facility in accordance with paragraph (d)(2)(ii) of this section. Owners and operators may choose which definition of reconstruction to apply and whether to comply with paragraph (d)(2)(i) or (ii) of this section; they do not need to apply both. If owners and operators choose to comply with paragraph (d)(2)(ii) of this section they may demonstrate compliance with § 60.15(b)(1) by showing that more than 50 percent of the number of natural gas-driven process controllers in the affected facility is replaced. That is, if an owner or operator meets the definition of reconstruction through the “number of controllers” criterion in (d)(2)(ii) of this section, they will have shown that the “fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility,” as required in § 60.15(b)(1). Therefore, an owner or operator may comply with the remaining provisions of § 60.15 that reference “fixed capital cost” through an initial showing that the number of natural gas-driven process controllers replaced exceeds 50 percent. For purposes of paragraphs (d)(2)(i) and (ii), “commenced” means that an owner or operator has undertaken a continuous program of natural gas-driven process controller replacement or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of natural gas-driven process controller replacement.

(i) If the owner or operator applies the definition of reconstruction in § 60.15(b)(1), reconstruction occurs when the fixed capital cost of the new process controllers exceeds 50 percent of the fixed capital cost that would be required to replace all the natural gas-driven process controllers in the affected facility. The “fixed capital cost of the new process controllers” includes the fixed capital cost of all natural gas-driven process controllers which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 24-month rolling period following December 6, 2022.

(ii) If the owner or operator applies the definition of reconstruction based on the percentage of natural gas-driven process controllers replaced, reconstruction occurs when greater than 50 percent of the natural gas-driven process controllers at a site are replaced. The percentage includes all natural gas-driven process controllers which are or will be replaced pursuant to all continuous programs of natural gas-driven process controller replacement which are commenced within any 24-month rolling period following December 6, 2022. If an owner or operator determines reconstruction based on the

percentage of natural gas-driven process controllers that are replaced, the owner or operator must also comply with § 60.15(a).

(e) Each storage vessel affected facility, which is a tank battery that has the potential for emissions as specified in either paragraph (e)(1)(i) or (ii) of this section. A tank battery with the potential for emissions below both of the thresholds specified in paragraphs (e)(1)(i) and (ii) of this section is not a storage vessel affected facility provided the owner/operator keeps records of the potential for emissions calculation for the life of the storage vessel or until such time the tank battery becomes a storage vessel affected facility because the potential for emissions meets or exceeds either threshold specified in either paragraph (e)(1)(i) or (ii) of this section.

(1)

(i) Potential for VOC emissions equal to or greater than 6 tons per year (tpy) as determined in paragraph (e)(2) of this section.

(ii) Potential for methane emissions equal to or greater than 20 tpy as determined in paragraph (e)(2) of this section.

(2) The potential for VOC and methane emissions must be calculated as the cumulative emissions from all storage vessels within the tank battery as specified by the applicable requirements in paragraphs (e)(2)(i) through (iii) of this section. The determination may take into account requirements under a legally and practicably enforceable limit in an operating permit or other requirement established under a Federal, state, local, or Tribal authority.

(i) Beginning January 22, 2027, or upon startup, whichever is later, for purposes of determining the applicability of a storage vessel tank battery as an affected facility, a legally and practicably enforceable limit must include the elements provided in paragraphs (e)(2)(i)(A) through (F) of this section.

(A) A quantitative production limit and quantitative operational limit(s) for the equipment, or quantitative operational limits for the equipment;

(B) An averaging time period for the production limit in (e)(2)(i)(A) of this section, if a production-based limit is used, that is equal to or less than 30 days;

(C) Established parametric limits for the production and/or operational limit(s) in paragraph (e)(2)(i)(A) of this section, and where a control device is used to achieve an operational limit, an initial compliance demonstration (*i.e.*, performance test) for the control device that establishes the parametric limits;

(D) Ongoing monitoring of the parametric limits in (e)(2)(i)(C) of this section that demonstrates continuous compliance with the production and/or operational limit(s) in (e)(2)(i)(A) of this section;

(E) Recordkeeping by the owner or operator that demonstrates continuous compliance with the limit(s) in (e)(2)(i)(A) through (D) of this section; and

(F) Periodic reporting that demonstrates continuous compliance.

(ii) For each tank battery located at a well site or centralized production facility, you must determine the potential for VOC and methane emissions within 30 days after startup of production, or within 30 days after an action specified in paragraphs (e)(3)(i) and (ii) of this section, except as provided in paragraph (e)(5)(iv) of this section. Beginning January 22, 2027, the potential for VOC and methane emissions must be calculated using a generally accepted model or calculation methodology that accounts for flashing, working, and breathing losses, based on the maximum average daily throughput to the tank battery determined for a 30-day period of production.

(iii) For each tank battery not located at a well site or centralized production facility, including each tank battery located at a compressor station or onshore natural gas processing plant, you must determine the potential for VOC and methane emissions prior to startup of the compressor station, onshore natural gas processing plant, or other facility within 30 days after an action specified in paragraphs (e)(3)(i) and (ii) of this section, using either method described in paragraph (e)(2)(iii)(A) or (B) of this section.

(A) Determine the potential for VOC and methane emissions using a generally accepted model or calculation methodology that accounts for flashing, working and breathing losses and based on the throughput to the tank battery established in a legally and practicably enforceable limit in an operating permit or other requirement established under a Federal, state, local, or Tribal authority; or

(B) Determine the potential for VOC and methane emissions using a generally accepted model or calculation methodology that accounts for flashing, working and breathing losses and based on projected maximum average daily throughput. Maximum average daily throughput is determined using a generally accepted engineering model (*e.g.*, volumetric condensate rates from the tank battery based on the maximum gas throughput capacity of each producing facility) to project the maximum average daily throughput for the tank battery.

(3) For the purposes of § 60.5395b, the following definitions of “reconstruction” and “modification” apply for determining when an existing tank battery becomes a storage vessel affected facility under this subpart.

(i) “Reconstruction” of a tank battery occurs when the potential for VOC or methane emissions to meet or exceed either of the thresholds specified in paragraphs (e)(1)(i) or (ii) of this section and—

(A) At least half of the storage vessels are replaced in the existing tank battery that consists of more than one storage vessel; or

(B) The provisions of § 60.15 are met for the existing tank battery.

(ii) “Modification” of a tank battery occurs when any of the actions in paragraphs (e)(3)(ii)(A) through (D) of this section occurs and the potential for VOC or methane emissions meet or exceed either of the thresholds specified in paragraphs (e)(1)(i) or (ii) of this section.

(A) A storage vessel is added to an existing tank battery;

(B) One or more storage vessels are replaced such that the cumulative storage capacity of the existing tank battery increases;

(C) Beginning January 22, 2027, or upon startup, whichever is later, for tank batteries at well sites or centralized production facilities, an existing tank battery receives additional crude oil, condensate, intermediate hydrocarbons, or produced water throughput from actions, including but not limited to, the addition of operations or a production well, or changes to operations or a production well (including hydraulic fracturing or refracturing of the well).

(D) Beginning January 22, 2027, or upon startup, whichever is later, for tank batteries not located at a well site or centralized production facility, including each tank battery at compressor stations or onshore natural gas processing plants, an existing tank battery receives additional fluids which cumulatively exceed the throughput used in the most recent (*i.e.*, prior to an action in paragraph (e)(3)(ii)(A), (B), or (D) of this section) determination of the potential for VOC or methane emissions.

(4) 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.

(5) For storage vessels not subject to a legally and practicably enforceable limit in an operating permit or other requirement established under Federal, state, local, or Tribal authority, any vapor from the storage vessel that is recovered and routed to a process through a vapor recovery unit designed and operated as specified in this section is not required to be included in the determination of potential for VOC or methane emissions for purposes of determining affected facility status, provided you comply with the requirements of paragraphs (e)(5)(i) through (iv) of this section.

(i) You meet the cover requirements specified in § 60.5411b(b).

(ii) You meet the closed vent system requirements specified in § 60.5411b(a)(2) through (4) and (c).

(iii) You must maintain records that document compliance with paragraphs (e)(5)(i) and (ii) of this section.

(iv) 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)(5)(i) and (ii) 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.

(6) The requirements of this paragraph (e)(6) apply to each storage vessel affected facility immediately upon startup, startup of production, or return to service. A storage vessel affected facility or portion of a storage vessel affected facility that is reconnected to the original source of liquids remains a storage vessel affected facility subject to the same requirements that applied before being removed from service. Any storage vessel that is used to replace a storage vessel affected facility, or portion of a storage vessel affected facility, or used to expand a storage vessel affected facility assumes the affected facility status of the storage vessel affected facility being replaced or expanded.

(7) A storage vessel with a capacity greater than 100,000 gallons used to recycle water that has been passed through two stage separation is not a storage vessel affected facility.

(f) Each process unit equipment affected facility, which is the group of all equipment within a process unit at an onshore natural gas processing plant is an affected facility.

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

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

(g) Each sweetening unit affected facility as defined by paragraphs (g)(1) and (2) of this section.

(1) Each sweetening unit that processes natural gas produced from either onshore or offshore wells is an affected facility; and

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

(3) Facilities that have a design capacity less than 2 long tons per day (LT/D) of hydrogen sulfide (H₂S) in the acid gas (expressed as sulfur) are required to comply with recordkeeping and reporting requirements specified in § 60.5423b(e) but are not required to comply with §§ 60.5405b through 60.5407b and §§ 60.5410b(i) and 60.5415b(k).

(4) Sweetening facilities producing acid gas that is completely re-injected into oil-or-gas-bearing geologic strata or that is otherwise not released to the atmosphere are not subject to §§ 60.5405b through 60.5407b, 60.5410b(i), 60.5415b(k), and 60.5423b.

(h) Each pump affected facility, which is the collection of natural gas-driven pumps at a well site, centralized production facility, onshore natural gas processing plant, or a compressor station. Pumps that are not driven by natural gas are not included in the pump affected facility.

(1) For the purposes of § 60.5393b, in addition to the definition in § 60.14, a modification occurs when the number of natural gas-driven pumps in the affected facility is increased by one or more.

(2) For the purposes of § 60.5393b, owners and operators may choose to apply reconstruction as defined in § 60.15(b) based on the fixed capital cost of the new pumps in accordance with paragraph (h)(2)(i) of this section, or the definition of reconstruction based on the number of natural gas-driven pumps in the affected facility in accordance with paragraph (h)(2)(ii) of this section. Owners and operators may choose which definition of reconstruction to apply and whether to comply with paragraph (h)(2)(i) or (ii) of this section; they do not need to apply both. If owners and operators choose to comply with paragraph (h)(2)(ii) of this section they may demonstrate compliance with § 60.15(b)(1) by showing that more than 50 percent of the number of natural gas-driven pumps is replaced. That is, if an owner or operator meets the definition of reconstruction through the “number of pumps” criterion in paragraph (h)(2)(ii) of this section, they will have shown that the “fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility,” as required in § 60.15(b)(1). Therefore, an owner or operator may comply with the remaining provisions of § 60.15 that reference “fixed capital cost” through an initial showing that the number of natural gas-driven pumps replaced exceeds 50 percent. For purposes of paragraphs (h)(2)(i) and (ii) of this section, “commenced” means that an owner or operator has undertaken a continuous program of component replacement or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of natural gas-driven pump replacement.

(i) If the owner or operator applies the definition of reconstruction in § 60.15, reconstruction occurs when the fixed capital cost of the new pumps exceeds 50 percent of the fixed capital cost that would be required to replace all the natural gas-driven pumps in the affected facility. The “fixed capital cost of the new pumps” includes the fixed capital cost of all natural gas-driven pumps which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 24-month rolling period following December 6, 2022.

(ii) If the owner or operator applies the definition of reconstruction based on the percentage of natural gas-driven pumps replaced, reconstruction occurs when greater than 50 percent of the natural gas-driven pumps in the affected facility are replaced. The percentage includes all natural gas-driven pumps which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 24-month rolling period following December 6, 2022. If an owner or operator determines reconstruction based on the percentage of natural gas-driven pumps that are replaced, the owner or operator must comply with § 60.15(a).

(3) A natural gas-driven pump that is in operation less than 90 days per calendar year is not part of an affected facility under this subpart. For the purposes of this section, any period of operation during a calendar day counts toward the 90-calendar day threshold.

(i) Each fugitive emissions components affected facility, which is the collection of fugitive emissions components at a well site, centralized production facility, or a compressor station.

(1) For purposes of § 60.5397b and § 60.5398b, a “modification” to a well site occurs when:

(i) A new well is drilled at an existing well site;

- (ii) A well at an existing well site is hydraulically fractured; or
 - (iii) A well at an existing well site is hydraulically refractured.
- (2) For purposes of § 60.5397b and § 60.5398b, a “modification” to centralized production facility occurs when:
- (i) Any of the actions in paragraphs (i)(1)(i) through (iii) of this section occurs at an existing centralized production facility;
 - (ii) A well sending production to an existing centralized production facility is modified, as defined in paragraphs (i)(1)(i) through (iii) of this section; or
 - (iii) A well site subject to the requirements of § 60.5397b or § 60.5398b removes all major production and processing equipment, such that it becomes a wellhead only well site and sends production to an existing centralized production facility.
- (3) For purposes of §§ 60.5397b and 60.5398b, a “modification” to a compressor station occurs when:
- (i) An additional compressor is installed at a compressor station; or
 - (ii) One or more compressors at a compressor station is replaced by one or more compressors of greater total horsepower than the compressor(s) being replaced. When one or more compressors is replaced by one or more compressors of an equal or smaller total horsepower than the compressor(s) being replaced, installation of the replacement compressor(s) does not trigger a modification of the compressor station for purposes of §§ 60.5397b and 60.5398b.

§ 60.5370b When must I comply with this subpart?

(a) You must be in compliance with the standards of this subpart no later than May 7, 2024 or upon initial startup, whichever date is later, except as specified in paragraph (a)(1) of this section for reciprocating compressor affected facilities, paragraphs (a)(2) and (3) of this section for storage vessel affected facilities, paragraph (a)(4) of this section for process unit equipment affected facilities at onshore natural gas processing plants, paragraph (a)(5) of this section for process controllers, paragraph (a)(6) of this section for pumps, paragraph (a)(7) of this section for centrifugal compressor affected facilities, paragraph (a)(8) of this section for enclosed combustion devices, paragraph (a)(9) of this section for enclosed combustion devices or flares, and paragraphs § 60.5377b(b) or (c) for associated gas wells.

- (1) You must comply with the requirements of § 60.5385b for your reciprocating compressor affected facility as specified in paragraph (a)(1)(i), (ii), or (iii) of this section, as applicable.
- (i) You must comply with the requirements of § 60.5385b(a)(1) on or before 8,760 hours of operation after May 7, 2024, on or before 8,760 hours of operation after last rod packing replacement, or on or before 8,760 hours of operation after startup, whichever date is later; and
 - (ii) You must comply with the requirements of § 60.5385b(a)(2) within 8,760 hours after compliance with § 60.5385b(a)(1) and (d)(3).
 - (iii) You must comply with the requirements of § 60.5385b(d)(1) and (2) for your reciprocating compressor upon initial startup.
- (2) You must comply with the requirements of paragraphs § 60.5395b(a)(1) for your storage vessel affected facility as specified in paragraphs (a)(2)(i) or (ii) of this section, as applicable.
- (i) Within 30 days after startup of production, or within 30 days after reconstruction or modification of the storage vessel affected facility, for each storage vessel affected facility located at a well site or centralized production facility.

- (ii) Prior to startup of the compressor station or onshore natural gas processing plant, or within 30 days after reconstruction or modification of the storage vessel affected facility, for each storage vessel affected facility located at a compressor station or onshore natural gas processing plant.
- (3) You must comply with the requirements of paragraph § 60.5395b(a)(2) as specified in paragraph (a)(3)(i) or (ii) of this section, as applicable:
 - (i) For each storage vessel affected facility located at a well site or centralized production facility, you must achieve the required emissions reductions within 30 days after the determination in paragraph (a)(2)(i) of this section.
 - (ii) For storage vessel affected facilities located at a compressor station or onshore natural gas processing plant, you must achieve the required emissions reductions within 30 days after the determination in paragraph (a)(2)(ii) of this section.
- (4) Except as specified in paragraph (a)(4)(i) and (ii) of this section, you must comply with the requirements of § 60.5400b or as an alternative, the requirements in § 60.5401b, for all process unit equipment affected facilities at a natural gas processing plant, as soon as practicable but no later than 180 days after the initial startup of the process unit.
 - (i) If complying with § 60.5400b, beginning January 22, 2027, or 180 days after startup, whichever is later, you must comply with the requirements of § 60.5400b(h)(2)(ii).
 - (ii) If complying with § 60.5401b, beginning January 22, 2027, or 180 days after startup, whichever is later, you must comply with the requirements of § 60.5401b(i)(2)(ii).
- (5) For process controller affected facilities, you must comply with the requirements of paragraph (a)(5)(i) or (ii) of this section, as applicable.
 - (i) Any process controller affected facilities may comply with § 60.5390b(b)(1) and (2) or (3) as an alternative to compliance with § 60.5390b(a) until January 22, 2027.
 - (ii) On or after January 22, 2027, process controller affected facilities must comply with § 60.5390b(a) or (b), as specified in those paragraphs.
- (6) For pump affected facilities, you must comply with the requirements of paragraph (a)(6)(i) or (ii) of this section, as applicable.
 - (i) Any pump affected facility may comply with § 60.5393b(b)(2) through (8), as applicable, as an alternative to compliance with § 60.5393b(a) until May 7, 2025.
 - (ii) On or after May 7, 2025, pump affected facilities must comply with § 60.5393b(a) or (b), as specified in those paragraphs.
- (7) For centrifugal compressor affected facilities, you must comply with the requirements of paragraph (a)(7)(i) or (ii) of this section, as applicable.
 - (i) You must comply with the requirements of § 60.5380b(a)(1) and (2) or (a)(3) for your centrifugal compressor upon initial startup.
 - (ii) Each centrifugal compressor affected facility that uses dry seals, each self-contained wet seal compressor, and each centrifugal compressor on the Alaska North Slope equipped with sour seal oil separator and capture system, complying with one of the alternatives in § 60.5380b(a)(4), (5), or (6), must comply with the specified performance-based volumetric flow rate work practice standards on or before 8,760 hours of operation after May 7, 2024, on or before 8,760 hours of operation after last seal replacement, or on or before 8,760 hours of operation after startup, whichever date is later.

(8) For an enclosed combustion device, you must comply with the requirements of paragraph (a)(8)(i) of this section, as applicable.

(i) Beginning January 22, 2027, or 180 days after startup, whichever is later, you must comply with the performance testing procedures of § 60.5413b(b).

(ii) [Reserved]

(9) For an enclosed combustion device or for a flare, you must comply with the requirements of paragraph (a)(9)(i), (ii), or (iii) of this section, as applicable.

(i) Beginning November 28, 2025, or 180 days after startup, whichever is later, you must comply with the continuous monitoring systems requirements of § 60.5417b(d)(8)(i) through (iv).

(ii) Beginning May 7, 2024 or 180 days after startup, whichever is later, you must comply with the visible emission observation requirements of § 60.5417b(d)(8)(v).

(iii) Beginning November 28, 2025, or 180 days after startup, whichever is later, you must comply with the continuous monitoring systems requirements of § 60.5417b(d)(8)(vi) for enclosed combustion devices or flares that are air-assisted or steam-assisted.

(b) At all times, including periods of startup, shutdown, and malfunction, owners and operators shall maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source. The provisions for exemption from compliance during periods of startup, shutdown and malfunctions provided for in 40 CFR 60.8(c) do not apply to this subpart.

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

§ 60.5371b What GHG and VOC standards apply to super-emitter events?

The provisions of this section will not apply between July 31, 2025, and January 22, 2027. The provisions of this section will apply after January 22, 2027. This section applies to super-emitter events. For purposes of this section, a super-emitter event is defined as any emissions event that is located at or near an oil and natural gas facility (*e.g.*, individual well site, centralized production facility, natural gas processing plant, or compressor station) and that is detected using remote detection methods and has quantified emission rate of 100 kg/hr of methane or greater. Paragraph (a) of this section describes the qualifications one must meet to apply to be a third-party notifier of super-emitter events. Paragraph (b) of this section describes the procedures for certifying third-party notifiers, as well as the procedures for petitioning the Agency for removal of a third-party notifier from the list of certified notifiers. Paragraph (c) of this section contains the required information that must be included in any notification submitted to the EPA from a certified third-party notifier and a timetable for notifications. The EPA shall review these notifications and if the EPA determines the notification is complete and does not contain information that the EPA finds to be erroneous or inaccurate to a reasonable degree of certainty, the EPA shall assign the notification a unique notification identification number, provide the notification to the owner or operator of the oil and natural gas facility identified in the notification, and post the notification, except for the owner/operator attribution, at www.epa.gov/super-emitter. Upon receiving such notification, owners or operators must take the actions listed in paragraphs (d) and (e) of this section. The EPA shall post the reports submitted under paragraph (e) of this section, § 60.5371(b) and § 60.5371a(b) of subparts OOOO and OOOOa of this part, and applicable State or Federal plan implementing § 60.5388c(b) of subpart OOOOc of this part, including owner/operator attributions that have been confirmed by the reports; where the reporting deadlines have

passed but no reports have been received, the EPA intends to post owner/operator attributions that the EPA reasonably believes to be accurate. The reports will be publicly available at www.epa.gov/super-emitter.

(a) *Qualifications for third-party notifiers.* An entity may apply to the Administrator under paragraph (b) of this section for approval as a third-party notifier if it meets the qualifications in this paragraph (a). The entity must be a person, as defined in 42 U.S.C. 7602(e), excluding the owner or operator of the site where the super-emitter event is detected, the Administrator, or the delegated authority. The entity must use a method that has been approved under § 60.5398b(d) for one of the technologies specified in paragraphs (a)(1) through (3) of this section.

(1) Satellite detection of methane emissions.

(2) Remote-sensing equipment on aircraft.

(3) Mobile monitoring platforms.

(b) *Third-party notifier certification.* An entity meeting the qualifications in paragraph (a) of this section may apply to be certified as a third-party notifier. Only entities certified as third-party notifiers may submit information on super-emitter events to the EPA under paragraph (c) of this section. An entity seeking certification as a third-party notifier must submit a request to the Administrator as described in paragraph (b)(1) of this section. Certified third-party notifiers must follow the recordkeeping requirements in paragraph (b)(2) of this section; failure to maintain the required records may result in loss of certification status. The Administrator will determine whether the request for certification is adequate and issue an approval or disapproval of the request as described in paragraph (b)(3) of this section. A certified third-party notifier must re-apply when material changes are made, as described in paragraph (b)(4) of this section. A third-party notifier may be removed from the list of certified notifiers as detailed in paragraph (b)(5) of this section.

(1) A request to be certified as a third-party notifier must be submitted to: U.S. EPA, Attn: Leader, Measurement Technology Group, Mail Drop: E143-02, 109 T.W. Alexander Drive, P.O. Box 12055, RTP, NC 27711. The request must include the supporting information in paragraphs (b)(1)(i) through (vi) of this section. If your submittal includes information claimed to be CBI, submit the portion of the information claimed as CBI to the OAQPS CBI office. The preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol, or other online file sharing services. Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address oaqpscbi@epa.gov and should include clear CBI markings and be flagged to the attention of the Leader, Measurement Technology Group. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if you do not have your own file sharing service, please email oaqpscbi@epa.gov to request a file transfer link. If you cannot transmit the file electronically, you may send CBI information through the postal service to the following address: U.S. EPA, Attn: OAQPS Document Control Officer and Measurement Technology Group Leader, Mail Drop: C404-02, 109 T.W. Alexander Drive, P.O. Box 12055, RTP, NC 27711. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

(i) General identification information for the candidate third-party notifier requesting certification as a third-party notifier including the mailing address, the physical address, the name of a principal officer and an email address for the principal officer, and name of the certifying official(s) and the certifying official(s)'s email address.

(ii) Description of the technologies the entity will use to identify emissions that are 100 kg/hr of methane or greater. At a minimum, the description must include the following:

(A) Reference to the approval of the method to be used under § 60.5398b(d).

(B) Memorandum of Understanding (MOU) or contracting agreements with the technology provider(s) that will be used to identify super-emitter events (if applicable).

- (iii) Curriculum vitae of the certifying official(s) detailing their work history, education, skill set, and training for evaluating the results of the technologies that will be used to identify super-emitter events.
 - (iv) The candidate third-party notifier's standard operating procedure(s) detailing the procedures and processes for data review. At a minimum, this must include the following:
 - (A) Procedures for evaluating the emission data provided by the technology, including the accuracy of the data and whether the data was collected in compliance with the method requirements approved under § 60.5398b(d).
 - (B) Process for verifying the accuracy of the locality of emissions.
 - (C) Process for identifying and verifying the owner or operator of a site where a super-emitter event occurs, including the source of information that will be used to make the identification.
 - (D) Procedures for handling potentially erroneous data.
 - (v) Description of the systems used for maintaining essential records identified in paragraph (b)(2) of this section.
 - (vi) A Quality Management Plan consistent with EPA's Quality Management Plan Standard (Directive No: CIO 2015-S-01.0, January 17, 2023) for Non-EPA organizations.
- (2) Certified third-party notifiers must maintain the records identified in paragraphs (b)(2)(i) through (iii) of this section. Upon request, the certified third-party notifier must make these records available to the Administrator for review.
- (i) Records for all surveys conducted by or sponsored by the certified third-party notifier, including outputs (*e.g.*, emission rates, locations) and associated data needed to confirm the accuracy of the outputs and the performance of the method used.
 - (ii) Records of all notifications of super-emitter events provided to the EPA. Retain any information collected that is used to evaluate the validity of a super-emitter event but which is not required to be submitted as part of the notification.
 - (iii) A copy of any records and/or identification of any databases used in the identification of the potential owner or operator of the site where a super-emitter event occurred.
- (3) Based upon the Administrator's judgment of the completeness, reasonableness, and accuracy of the entity's request, the Administrator will approve or disapprove the entity for certification as a third-party notifier. For those third parties that receive approval, the Administrator will provide you a unique notifier ID. Starting 15 calendar days after being approved as a certified third-party notifier, the notifier may submit notifications of super-emitter events to the EPA as outlined in paragraph (c) of this section. All approved third-party notifiers shall be posted on the EPA website at www.epa.gov/emc-third-party-certifications.
- (4) If a third-party notifier intends to make any significant changes to their procedures for identifying super-emitter events, meaning a change to the technology used to identify super-emitter events or a change to the certifying official(s), you must request an amendment to your certification and be recertified under paragraph (b)(1) of this section.
- (5) A certified third-party notifier may be removed from the list of approved third-party notifiers in any of the circumstances listed in paragraphs (b)(5)(i) through (iii) of this section. Entities removed from the list of approved third-party notifiers cannot submit notifications to the EPA under paragraph (c) of this section. Entities may be added back to the list of approved third-party notifiers by receiving approval of a new certification request submitted under paragraph (b)(1) of this section.

- (i) If a certified third-party notifier has made material changes to their procedures for identifying super-emitter events, meaning a change to the technology used to identify super-emitter events or a change to the certifying official, without seeking recertification.
- (ii) If the Administrator finds that the certified third-party notifier has persistently submitted data with significant errors (*e.g.*, misidentification of the owner or operator) or if the third-party notifier has engaged in illegal activity during the assessment of a super-emitter event (*e.g.*, trespassing).
- (iii) If the Administrator receives a petition from an owner or operator to remove a certified third-party notifier from the list of approved notifiers, as set forth below, and the Administrator makes the finding noted below. Any owner or operator that has received more than three notices with meaningful and/or demonstrable errors of a super-emitter event at the same oil and natural gas facility (*e.g.*, a well site, centralized production facility, natural gas processing plant, or compressor station) from the EPA that were submitted to the EPA by the same third party may petition the Administrator to remove that third party from the list of approved notifiers, by providing evidence that the claimed super-emitter events did not occur. Such petitions may not be used to dispute the methodology that were approved through the process described in § 60.5398b(d). The third party will be given the opportunity to respond to the petition. If, in the Administrator's discretion, the Administrator determines that the three notifications contain meaningful and/or demonstrable errors, including that the third party did not use the methane detection technology identified in their submittal, the emissions event did not exceed the threshold of 100 kg/hr of methane, the third-party knowingly misidentified the date of a super-emitter event, the third party may be removed by the Administrator from the list of approved notifiers. The failure of the owner or operator to find the source of the super-emitter event upon subsequent inspection shall not be proof, by itself, of demonstrable error.

(c) *Notification of super-emitter events.* Notifications must be submitted to the EPA using the Super-Emitter Program Portal (available at <http://www.epa.gov/super-emitter>). Notifications must contain the information specified in paragraphs (c)(1) through (8) of this section. The EPA will review the submitted notifications of super-emitter events for completeness and accuracy. If the EPA determines that the notification is complete and does not contain information that the EPA finds to be inaccurate to a reasonable degree of certainty, the EPA will assign the notification a unique notification report identification number, make the notification publicly available at www.epa.gov/super-emitter, and provide the super-emitter event notification to the owner or operator identified in the notification. The EPA will not review and provide the notification to an owner or operator if the notification is submitted after the date specified in paragraph (c)(9) of this section.

- (1) Unique Third-Party Notifier ID.
- (2) Date of detection of the super-emitter event. If multiple surveys were required to detect and quantify the super-emitter event, the date of detection is the date of the final survey.
- (3) Location of super-emitter event in latitude and longitude coordinates in decimal degrees to an accuracy and precision of four (4) decimals of a degree using the North American Datum of 1983.
- (4) Owner(s) or operator(s) of any oil and natural gas facility (*e.g.*, individual well site, centralized production facility, natural gas processing plant, or compressor station) within 50 meters of the latitude and longitude coordinates of the super-emitter event, if available.
- (5) Identification of the detection technology and reference to the approval of the technology used under § 60.5398b(d).
- (6) Documentation (*e.g.*, imagery) depicting the detected super-emitter event and the site from which the super-emitter event was detected.

(7) Quantified emission rate of the super-emitter event in kg/hr and associated uncertainty bounds (*e.g.*, 1- σ) of the measurement.

(8) Attestation statement, signed and dated by the third-party notifier certifying official submitting the data collected. The attestation must state: "I certify that I have been approved to be a notifier under 40 CFR 60.5371b(b) and that the emission detection information included in this notification was collected and interpreted as described in this notification. Based on my professional knowledge and experience, and inquiry of personnel involved in the collection and analysis of the data, the certification submitted herein is true, accurate, and complete."

(9) The third-party notifier must submit the notification within 15 calendar days of the date of detection of the super-emitter event.

(d) *Identification of super-emitter events.* Within 5 calendar days of receiving a notification from the EPA of a super-emitter event, the owner or operator of an oil and natural gas facility (*e.g.*, a well site, centralized production facility, natural gas processing plant, or compressor station) must initiate a super-emitter event investigation. The investigation must be conducted in accordance with this paragraph (d) and completed within 15 days of receiving the notification from the EPA. The owner or operator must maintain records of its super-emitter event investigations and report the findings from the investigation according to the requirements in paragraph (e) of this section.

(1) If you do not own or operate an oil and natural gas facility within 50 meters from the latitude and longitude provided in the notification, report this result to the EPA under paragraph (e) of this section. Your super-emitter event investigation is deemed complete.

(2) If you own or operate an oil and natural gas facility within 50 meters from the latitude and longitude provided in the notification, you must investigate to determine the source of super-emitter event. The investigation may include but is not limited to the actions specified below in paragraphs (d)(2)(i) through (v) of this section.

(i) Review any maintenance activities (*e.g.*, liquids unloading) or process activities from the affected facilities subject to regulation under this subpart, starting from the date of detection of the super-emitter event as identified in the notification, until the date of investigation, to determine if the activities indicate any potential source(s) of the super-emitter event emissions.

(ii) Review all monitoring data from control devices (*e.g.*, flares) from the affected facilities subject to regulation under this subpart from the initial date of detection of the super-emitter event as identified in the notification until the date of receiving the notification from the EPA. Identify any malfunctions of control devices or periods when the control devices were not in compliance with applicable requirements and that indicate a potential source of the super-emitter event emissions.

(iii) If you conducted a fugitive emissions survey or periodic screening event in accordance with § 60.5397b or § 60.5398b(b) between the initial date of detection of the super-emitter event as identified in the notification and the date the notification from the EPA was received, review the results of the survey to identify any potential source(s) of the super-emitter event emissions.

(iv) If you conduct continuous monitoring with advanced methane detection technology in accordance with § 60.5398b(c), review the monitoring data collected on or after the initial date of detection of the super-emitter event as identified in the notification, until the date of receiving the notification from the EPA.

(v) Screen the entire oil and natural gas facility with OGI, Method 21 of appendix A-7 to this part, or an alternative test method(s) approved per § 60.5398b(d), to determine if a super-emitter event is present.

(3) If the source of the super-emitter event was found to be from fugitive emission components at a well site, centralized production facility, or compressor station subject to this subpart, you must comply with the repair requirements under § 60.5397b and the associated recordkeeping and reporting requirements under § 60.5420b(b)(9) and (c)(14).

(e) *Super-emitter event report.* You must submit the results of the super-emitter event investigation conducted under paragraph (d) of this section to the EPA in accordance with paragraph (e)(1) of this section. If the super-emitter event (*i.e.*, emission at 100 kg/hr of methane or more) is ongoing at the time of the initial report, submit the additional information in accordance with paragraph (e)(2) of this section. You must attest to the information included in the report as specified in paragraph (e)(3) of this section.

(1) Within 15 days of receiving a notification from the EPA under paragraph (c) of this section, you must submit a report of the super-emitter event investigation conducted under paragraph (d) of this section through the Super-Emitter Program Portal. You must include the applicable information in paragraphs (e)(1)(i) through (viii) of this section in the report. If you have identified a demonstrable error in the notification, the report may include a statement of the demonstrable error.

(i) Notification Report ID of the super-emitter event notification.

(ii) Identification of whether you are the owner or operator of an oil and natural gas facility within 50 meters from the latitude and longitude provided in the EPA notification. If you do not own or operate an oil and natural gas facility within 50 meters from the latitude and longitude provided in the EPA notification, you are not required to report the information in paragraphs (e)(1)(iii) through (viii) of this section.

(iii) General identification information for the facility, including, facility name, the physical address, applicable ID Number (*e.g.*, EPA ID Number, API Well ID Number), the owner or operator or responsible official (where applicable) and their email address.

(iv) Identification of whether there is an affected facility or associated equipment subject to regulation under this subpart at this oil and natural gas facility.

(v) Indication of whether you were able to identify the source of the super-emitter event. If you indicate you were unable to identify the source of the super-emitter event, you must certify that all applicable investigations specified in paragraphs (d)(2)(i) through (v) of this section have been conducted for all affected facilities and associated equipment subject to this subpart that are at this oil and natural gas facility, and you have determined that the affected facilities and associated equipment are not the source of the super-emitter event. If you indicate that you were not able to identify the source of the super-emitter event, you are not required to report the information in paragraphs (e)(1)(vi) through (viii) of this section.

(vi) The source(s) of the super-emitter event.

(vii) Identification of whether the source of the super-emitter event is equipment subject to regulation under this subpart. If the source of the super-emitter event is equipment subject to regulation under this subpart, identify the applicable regulation(s) under this subpart.

(viii) Indication of whether the super-emitter event is ongoing at the time of the initial report submittal (*i.e.*, emissions at 100 kg/hr of methane or more).

(A) If the super-emitter event is not ongoing at the time of the initial report submittal, provide the actual (or if unknown) estimated date and time the super-emitter event ended.

(B) If the super-emitter event is ongoing at the time of the initial report submittal, provide a short narrative of your plan to end the super-emitter event, including the targeted end date for the efforts to be completed and the super-emitter event ended.

(2) If the super-emitter event is ongoing at the time of the initial report submittal, within 5 business days of the date the super-emitter event ends, you must update your initial report through the Super-Emitter Program Portal to provide the end date and time of the super-emitter event.

(3) You must sign the following attestation when submitting data into the Super-Emitter Program Portal: "I certify that the information provided in this report regarding the specified super-emitter event was prepared under my direction or supervision. I further certify that the investigations were conducted, and this report was prepared pursuant to the requirements of § 60.5371b(d) and (e). Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete. I am aware that knowingly false statements may be punishable by fine or imprisonment."

§ 60.5375b What GHG and VOC standards apply to well completions at well affected facilities?

(a) You must comply with the requirements of paragraphs (a)(1) through (3) of this section for each well completion operation with hydraulic fracturing and refracturing at a well affected facility, except as provided in paragraphs (f), (g) and (h) of this section. You must maintain a log as specified in paragraph (b) of this section.

(1) For each stage of the well completion operation, follow the requirements specified in paragraphs (a)(1)(i) through (iii) of this section.

(i) During the initial flowback stage, route the flowback into one or more well completion vessels or storage vessels and commence operation of a separator unless it is technically infeasible for a separator to function. The separator may be a production separator, but the production separator also must be designed to accommodate flowback. Any gas present in the initial flowback stage is not subject to control under this section.

(ii) During the separation flowback stage, route all recovered liquids from the separator to one or more well completion vessels or storage vessels, re-inject the recovered liquids into the well or another well, or route the recovered liquids to a collection system. Route the recovered gas from the separator into a gas flow line or collection system, re-inject the recovered gas into the well or another well, use the recovered gas as an onsite fuel source, or use the recovered gas for another useful purpose that a purchased fuel or raw material would serve. If it is technically infeasible to route the recovered gas as required above, follow the requirements of paragraph (a)(2) of this section. If, at any time during the separation flowback stage, it is technically infeasible for a separator to function, you must comply with paragraph (a)(1)(i) of this section.

(iii) You must have the separator onsite or otherwise available for use at a centralized production facility or well pad that services the well completion affected facility during well completions. The separator must be available and ready for use to comply with paragraph (a)(1)(ii) of this section during the entirety of the flowback period, except as provided in paragraphs (a)(1)(iii)(A) through (C) of this section.

(A) A well that is not hydraulically fractured or refractured with liquids, or that does not generate condensate, intermediate hydrocarbon liquids, or produced water such that there is no liquid collection system at the well site is not required to have a separator onsite.

(B) If conditions allow for liquid collection, then the operator must immediately stop the well completion operation, install a separator, and restart the well completion operation in accordance with paragraph (a)(1) of this section.

(C) The owner or operator of a well that meets the criteria of paragraph (a)(1)(iii)(A) or (B) of this section must submit the report in § 60.5420b(b)(2) and maintain the records in § 60.5420b(c)(1)(iii).

(2) If it is technically infeasible to route the recovered gas as required in paragraph (a)(1)(ii) of this section, then you must capture and direct recovered gas to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways. After January 22, 2027, completion combustion devices must be equipped with a reliable continuous pilot flame.

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

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

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

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

(e) You must perform the required notification, reporting and recordkeeping as required by § 60.5420b(a)(2), (b)(1) and (2), and (c)(1).

(f) For each well affected facility specified in paragraphs (f)(1) and (2) of this section, you must comply with the requirements of paragraphs (f)(3) and (4) of this section.

(1) Each well completion operation with hydraulic fracturing at a wildcat or delineation well.

(2) Each well completion operation with hydraulic fracturing at a non-wildcat low pressure well or non-delineation low pressure well.

(3) You must comply with paragraph (f)(3)(i) of this section. You must also comply with paragraph (b) of this section. As an alternative, if you are able to operate a separator, you may comply with paragraph (b) and (f)(3)(ii) of this section. Compliance with paragraphs (f)(3)(i) or (ii) of this section is not required if you meet the requirements of paragraph (g) of this section.

(i) Route all flowback to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways. After January 22, 2027, completion combustion devices must be equipped with a reliable continuous pilot flame.

(ii) Route all flowback into one or more well completion vessels and commence operation of a separator unless it is technically infeasible for a separator to function. You must have the separator onsite or otherwise available for use at the wildcat well, delineation well, or low pressure well. The separator must be available and ready for use to comply with paragraph (f)(3)(ii) of this section during the entirety of the flowback period. Any gas present in the flowback before the separator can function is not subject to control under this section. Capture and direct recovered gas to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost, or waterways. After January 22, 2027, completion combustion devices must be equipped with a reliable continuous pilot flame.

(4) You must submit the notification as specified in § 60.5420b(a)(2), submit annual reports as specified in § 60.5420b(b)(1) and (2) and maintain records specified in § 60.5420b(c)(1)(i) through (iii) and (vii) for each wildcat well, each delineation well, and each low pressure well.

(g) For each well completion affected facility with less than 300 scf of gas per stock tank barrel of oil produced, you must comply with paragraphs (g)(1) and (2) of this section.

(1) You must maintain records specified in § 60.5420b(c)(1)(vi).

(2) You must submit reports specified in § 60.5420b(b)(1) and (2).

(h) A well modified in accordance with § 60.5365b(a)(1)(ii) (*i.e.*, an existing well that is hydraulically refractured) is exempt from the well completion operation standards in paragraphs (b) through (d) of this section, when the requirements of paragraphs (a)(1) through (3) of this section are met.

§ 60.5376b What GHG and VOC standards apply to gas well liquids unloading operations at well affected facilities?

(a) *General requirements.* You must comply with the requirements of this section for each gas well liquids unloading operation at your gas well affected facility as specified by paragraphs (a)(1) and (2) of this section. You have a general duty to safely maximize resource recovery and minimize releases to the atmosphere during gas well liquids unloading operations.

(1) If a gas well liquids unloading operation technology or technique employed does not result in venting of methane and VOC emissions to the atmosphere, you must comply with the requirements specified in paragraphs (a)(1)(i) and (ii) and (d) and (e) of this section. If an unplanned venting event occurs, you must meet the requirements specified in paragraphs (c) through (f) of this section.

(i) Comply with the recordkeeping requirements specified in § 60.5420b(c)(2)(i).

(ii) Submit the information specified in § 60.5420b(b)(1) and (b)(3)(i) in the annual report.

(2) If a gas well liquids unloading operation technology or technique vents methane and VOC emissions to the atmosphere, you must comply with the requirements specified in paragraphs (b) and (c), or paragraph (g) of this section.

(b) *Work Practice Standards.* If a gas well liquids unloading operation employs a technology or technique that vents methane and VOC emissions to the atmosphere, you must comply with the requirements in paragraphs (b)(1) through (3) and paragraphs (c) through (f) of this section.

(1) Employ best management practices to minimize venting of methane and VOC emissions as specified in paragraph (c) of this section for each gas well liquids unloading operation.

(2) Comply with the recordkeeping requirements specified in § 60.5420b(c)(2)(ii).

(3) Submit the information specified in § 60.5420b(b)(1) and (b)(3)(ii) in the annual report.

(c) *Best management practice requirements.* For each gas well liquids unloading operation complying with paragraphs (a)(2) and (b) of this section, you must develop, maintain, and follow a best management practice plan to minimize venting of methane and VOC emissions to the maximum extent possible from each gas well liquids unloading operation. This best management practice plan must meet the minimum criteria specified in paragraphs (c)(1) through (4) of this section.

(1) Include steps that create a differential pressure to minimize the need to vent a well to unload liquids,

(2) Include steps to reduce wellbore pressure as much as possible prior to opening the well to the atmosphere,

(3) Unload liquids through the separator where feasible, and

(4) Close all wellhead vents to the atmosphere and return the well to production as soon as practicable.

(d) *Initial compliance.* You must demonstrate initial compliance with the standards that apply to well liquids unloading operations at your well affected facilities as required by § 60.5410b(b).

(e) *Continuous compliance.* You must demonstrate continuous compliance with the standards that apply to well liquids unloading operations at your well affected facilities as required by § 60.5415b(b).

(f) *Recordkeeping and reporting.* You must perform the required notification, recordkeeping and reporting requirements as specified in § 60.5420b(b)(3) and (c)(2).

(g) *Other compliance options.* Reduce methane and VOC emissions from well affected facility gas wells that unload liquids by 95.0 percent by complying with the requirements specified in paragraphs (g)(1) and (2) of this section and meeting the initial and continuous compliance and recordkeeping and reporting requirements specified in paragraphs (g)(3) through (5) of this section.

(1) You must route emissions through a closed vent system to a control device that meets the conditions specified in § 60.5412b.

(2) You must route emissions through a closed vent system that meets the requirements of § 60.5411b(a) and (c).

(3) You must demonstrate initial compliance with standards that apply to well affected facility gas well liquids unloading as required by § 60.5410b(b).

(4) You must demonstrate continuous compliance with standards that apply to well affected facility gas well liquids unloading as required by § 60.5415b(b).

(5) You must perform the reporting as required by § 60.5420b(b)(1), (3), and (11) through (13), as applicable, and the recordkeeping as required by § 60.5420b(c)(2), (8), and (10) through (13), as applicable.

§ 60.5377b What GHG and VOC standards apply to associated gas wells at well affected facilities?

(a) You must comply with either paragraph (a)(1), (2), (3), or (4) of this section for each associated gas well upon startup and at all times, except as provided in paragraphs (b) through (f) of this section. You must also comply with paragraphs (h), (i), and (j) of this section.

(1) Recover the associated gas from the separator and route the recovered gas into a gas gathering flow line or collection system to a sales line.

(2) Recover the associated gas from the separator and use the recovered gas as an onsite fuel source.

(3) Recover the associated gas from the separator and use the recovered gas for another useful purpose that a purchased fuel or raw material would serve.

(4) Recover the associated gas from the separator and reinject the recovered gas into the well or inject the recovered gas into another well.

(b) For associated gas wells that commenced construction between May 7, 2024 and May 7, 2026, you can comply with the requirements in paragraph (f) of this section continually upon startup instead of paragraph (a) of this section until May 7, 2026 if you demonstrate and certify that it is not feasible to comply with paragraphs (a)(1), (2), (3), and (4) of this section due to technical reasons in accordance with paragraph (g) of this section. After May 7, 2026 you must continually comply with paragraph (a) of this section at all times.

(c) For associated gas wells that commenced construction between December 6, 2022, and May 7, 2024, and for associated gas wells that undergo reconstruction or modification after December 6, 2022, you can comply with the requirements in paragraph (f) of this section instead of paragraph (a) of this section if you demonstrate and certify

that it is not feasible to comply with paragraph (a)(1), (2), (3), and (4) of this section due to technical reasons in accordance with paragraph (g) of this section. Associated gas wells that are modified or reconstructed must comply with paragraph (a) or (f) of this section upon startup and at all times thereafter.

(d) If you are complying with paragraph (a) of this section, you may temporarily route the associated gas to a flare or control device that achieves a 95.0 percent reduction in VOC and methane emissions in the situations and for the durations identified in paragraphs (d)(1), (2), (3), or (4) of this section. The associated gas must be routed through a closed vent system that meets the requirements of § 60.5411b(a) and (c) and the control device must meet the conditions specified in § 60.5412b during the period when the associated gas is routed to the flare. Records must be kept of all instances in which associated gas is temporarily routed to a flare or to a control device in accordance with § 60.5420b(c)(3)(i)(B) and reported in the annual report in accordance with § 60.5420b(b)(4)(i)(B).

(1) During a malfunction or incident that endangers the safety of operator personnel or the public you are allowed to route to a flare or control device for 24 hours or less per incident.

(2) During repair, maintenance including blow downs, a production test, or commissioning, you are allowed to route to a flare or control device for 24 hours or less per incident.

(3) For wells complying with paragraph (a)(1) of this section, during a temporary interruption in service from the gathering or pipeline system you are allowed to route to a flare or route to a control device for the duration of the temporary interruption not to exceed 30 days per incident.

(4) During periods when the composition of the associated gas does not meet pipeline specifications for sources complying with paragraph (a)(1) of this section, or when the composition of the associated gas does not meet the quality requirements for use as a fuel for sources complying with paragraph (a)(2) of this section, or when the composition of the associated gas does not meet the quality requirements for another useful purpose for sources complying with paragraph (a)(3) of this section, you are allowed to route to a flare or control device until the associated gas meets the required specifications or for 72 hours per incident, whichever is less.

(e) If you are complying with paragraph (a), (d), or (f) of this section, you may vent the associated gas in the situations and for the durations identified in paragraphs (e)(1), (2), or (3) of this section per incident. The cumulative period of venting must not exceed 24 hours for any calendar year. Records must be kept of all venting instances in accordance with § 60.5420b(c)(3)(ii) and reported in the annual report in accordance with § 60.5420b(b)(4)(ii).

(1) For up to 12 hours per incident to protect the safety of personnel.

(2) For up to 30 minutes per incident during bradenhead monitoring.

(3) For up to 30 minutes per incident during a packer leakage test.

(f) You must route the associated gas to a control device that reduces methane and VOC emissions by at least 95.0 percent. The associated gas must be routed through a closed vent system that meets the requirements of § 60.5411b(a) and (c) and the control device must meet the conditions specified in § 60.5412b.

(1) For associated gas wells identified in paragraph (b) of this section, you can comply with the requirements in paragraph (f) of this section for up to a one year period if you demonstrate and certify that it is not feasible to comply with paragraph (a)(1), (2), (3), and (4) of this section due to technical reasons in accordance with paragraph (g) of this section. This allowance is renewable each year with an updated technical infeasibility demonstration and certification in accordance with paragraph (g) of this section. Associated gas wells identified in paragraph (b) of this section are not allowed to comply with the requirements in paragraph (f) of this section after May 7, 2026.

(2) For associated gas wells identified in paragraph (c) of this section, you can comply with the requirements in paragraph (f) of this section for up to a one year period if you demonstrate and certify that it is not feasible to comply with paragraph (a)(1), (2), (3), and (4) of this section due to technical reasons in accordance with paragraph (g) of this section. This allowance is renewable each year with an updated technical infeasibility demonstration and certification in accordance with paragraph (g) of this section.

(g) For affected sources identified in paragraphs (b) and (c) of this section that are complying with the requirements in paragraph (f) of this section, you must demonstrate that it is not feasible to comply with paragraph (a)(1), (2), (3), and (4) of this section due to technical reasons by providing a detailed analysis documenting and certifying the technical reasons for this infeasibility.

(1) The demonstration must address the technical infeasibility for all options identified in (a)(1), (2), (3), and (4) of this section.

(2) This demonstration must be certified by a professional engineer or another qualified individual with expertise in the uses of associated gas. The following certification, signed and dated by the qualified professional engineer or other qualified individual shall state: "I certify that the assessment of technical and safety infeasibility was prepared under my direction or supervision. I further certify that the assessment was conducted, and this report was prepared pursuant to the requirements of § 60.5377b(b). Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete."

(3) This demonstration and certification are valid for no more than 12 months. You must re-analyze the feasibility of complying with paragraphs (a)(1), (2), (3), and (4) of this section and finalize a new demonstration and certification each year.

(4) Documentation of these demonstrations, along with the certifications, must be maintained in accordance with § 60.5420b(c)(3)(iii) and submitted in annual reports in accordance with § 60.5420b(b)(4)(iii)(C) and (D).

(h) You must demonstrate initial compliance with the standards that apply to associated gas wells as required by § 60.5410b(c).

(i) You must demonstrate continuous compliance with the standards that apply to associated gas wells as required by § 60.5415b(c).

(j) You must perform the reporting as required by § 60.5420b(b)(1) and (4), and (b)(11) and (12), as applicable; and the recordkeeping as required by § 60.5420b(c)(3) and (8), and (c)(10) through (13), as applicable.

§ 60.5380b What GHG and VOC standards apply to centrifugal compressor affected facilities?

Each centrifugal compressor affected facility must comply with the GHG and VOC standards in paragraphs (a) through (d) of this section.

(a) Each centrifugal compressor affected facility that uses wet seals must comply with the GHG and VOC standards in paragraphs (a)(1), (2), or (3) of this section. Each self-contained wet seal compressor, and each centrifugal compressor on the Alaska North Slope equipped with sour seal oil separator and capture system, must comply with the GHG and VOC standards in paragraphs (a)(1) and (2) of this section, or one of the alternatives in (a)(3) through (5) of this section, as applicable, and (a)(8) of this section. Each centrifugal compressor affected facility that uses dry seals must comply with paragraphs (a)(6) through (8) of this section, or with of the alternatives in paragraph (a)(9) of this section.

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

(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 § 60.5411b(b). The cover must be connected through a closed vent system that meets the requirements of § 60.5411b(a) and (c) and the closed vent system must be routed to a control device that meets the conditions specified in § 60.5412b.

(3) As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process. If you route the emissions to a process, you must equip the wet seal fluid degassing system with a cover that meets the requirements of § 60.5411b(b). The cover must be connected through a closed vent system that meets the requirements of § 60.5411b(a) and (c).

(4) If you own or operate a self-contained wet seal centrifugal compressor you may comply with the GHG and VOC requirements as specified in paragraph (a)(4)(i) through (iii) of this section, using volumetric flow rate as a surrogate, in lieu of meeting the requirements specified in paragraphs (a)(1) and (2) of this section. You must determine the volumetric flow rate in accordance with paragraph (a)(7)(i) of this section.

(i) The volumetric flow rate must not exceed 3 standard cubic feet per minute (scfm) per seal. If the individual seals are manifolded to a single open-ended vent line, the volumetric flow rate must not exceed the sum of the individual seals multiplied by 3 scfm. If the volumetric flow rate, measured in accordance with paragraph (a)(7)(i) of this section exceeds 3 scfm multiplied by the number of wet seals connected to the vent, the seals connected to the measured vent must be repaired as provided in paragraph (a)(8) of this section.

(ii) You must conduct your first volumetric flow rate measurement from your self-contained wet seal compressor on or before 8,760 hours of operation after May 7, 2024 or on or before 8,760 hours of operation after startup, whichever date is later.

(iii) You must conduct subsequent volumetric flow rate measurements from your self-contained wet seal centrifugal compressor on or before 8,760 hours of operation after the previous measurement which demonstrates compliance with the 3 scfm volumetric flow rate per seal. If the individual seals are manifolded to a single open-ended vent line, the volumetric flow rate must not exceed the sum of the individual seals multiplied by 3 scfm.

(5) If you own or operate a centrifugal compressor on the Alaska North Slope equipped with seal oil separator and capture system, you may comply with the GHG and VOC requirements specified in paragraphs (a)(5)(i) through (iii) of this section using volumetric flow rate as a surrogate, in lieu of meeting the requirements specified in paragraphs (a)(1) and (2). You must determine the volumetric flow rate in accordance with paragraph (a)(7)(ii) of this section.

(i) The volumetric flow rate per seal must not exceed 9 scfm per seal. If the individual seals are manifolded to a single open-ended vent line, the volumetric flow rate must not exceed the sum of the individual seals multiplied by 9 scfm. If the volumetric flow rate, measured in accordance with paragraph (a)(7)(ii) of this section exceeds 9 scfm multiplied by the number of wet seals connected to the vent, the seals connected to the measured vent must be repaired as provided in paragraph (a)(8) of this section.

(ii) You must conduct your first volumetric flow rate measurement from your Alaska North Slope centrifugal compressor equipped with a sour seal oil separator and capture system on or before 8,760 hours of operation after May 7, 2024 or on or before 8,760 hours of operation after startup, whichever date is later.

(iii) You must conduct subsequent volumetric flow rate measurements from your Alaska North Slope centrifugal compressor equipped with sour seal separator and capture system on or before 8,760 hours of operation after the previous measurement which demonstrates compliance with the 9 scfm

volumetric flow rate per seal. If the individual seals are manifolded to a single open-ended vent line, the volumetric flow rate must not exceed the sum of the individual seals multiplied by 9 scfm.

(6) If you own or operate a centrifugal compressor equipped with dry seals, you must comply with the GHG and VOC requirements as specified in paragraphs (a)(6)(i) through (iii), using volumetric flow rate as a surrogate. You must determine the volumetric flow rate in accordance with paragraph (a)(7)(iii) of this section.

(i) The volumetric flow rate per seal must not exceed 10 standard cubic feet per minute (scfm) per seal. If the individual seals are manifolded to a single open-ended vent line, the volumetric flow rate must not exceed the sum of the individual seals multiplied by 10 scfm. If the volumetric flow rate, measured in accordance with paragraph (a)(7)(iii) of this section exceeds 10 scfm multiplied by the number of dry seals connected to the vent, the seals connected to the measured vent must be repaired as provided in paragraph (a)(8) of this section.

(ii) You must conduct your first volumetric flow rate measurement from your centrifugal compressor equipped with a dry seal on or before 8,760 hours of operation after May 7, 2024 or on or before 8,760 hours of operation after startup, whichever date is later.

(iii) You must conduct subsequent volumetric flow rate measurements from your centrifugal compressor equipped with dry seals on or before 8,760 hours of operation after the previous measurement which demonstrates compliance with the 10 scfm volumetric flow rate per seal. If the individual seals are manifolded to a single open-ended vent line, the volumetric flow rate must not exceed the sum of the individual seals multiplied by 10 scfm.

(7) You must determine the volumetric flow rate for your centrifugal compressor, as specified in paragraphs (a)(7)(i) through (iii) of this section.

(i) You must determine the volumetric flow rate from your self-contained wet seal centrifugal compressor wet seal as specified in paragraph (a)(7)(i)(A) or (B) of this section. If the volumetric flow rate exceeds 3 scfm multiplied by the number of wet seals connected to the vent, the wet seals connected to the measured vent must be repaired as provided in paragraph (a)(8) of this section.

(A) For self-contained wet seal centrifugal compressors in operating-mode or in standby-pressurized-mode, determine volumetric flow rate at standard conditions from each self-contained wet seal centrifugal compressor wet seal using one of the methods specified in paragraphs (a)(7)(i)(A)(1) through (3) of this section.

(1) You may choose to use any of the methods set forth in § 60.5386b(a) to screen for leaks/emissions. For the purposes of this paragraph, when using any of the methods in § 60.5386b(a), emissions are detected whenever a leak is detected according to the method. If emissions are detected using the methods set forth in § 60.5386b(a), then you must use one of the methods specified in paragraph (a)(7)(i)(A)(2) or (3) of this section to determine the volumetric flow rate. If emissions are not detected using the methods in § 60.5386b(a), then you may assume that the volumetric emissions are zero.

(2) Use a temporary or permanent flow meter according to methods set forth in § 60.5386b(b).

(3) Use a high-volume sampler according to the method set forth in § 60.5386b(c).

(B) For conducting measurements on manifolded groups of self-contained wet seal centrifugal compressor seals, you must determine the volumetric flow rate from the self-contained wet seal centrifugal compressor seal as specified in paragraph (a)(7)(i)(B)(1) or (2) of this section.

(1) Measure at a single point in the manifold downstream of all self-contained wet seal centrifugal compressor seal inputs and, if practical, prior to comingling with other non-compressor emission sources.

(2) Determine the volumetric flow rate at standard conditions from the common stack using one of the methods specified in paragraph (a)(7)(i)(A)(1) through (3) of this section.

(ii) You must determine the volumetric flow rate from your centrifugal compressor on the Alaska North Slope equipped with sour seal oil separator and capture system as specified in paragraph (a)(7)(ii)(A) or (B) of this section. If the volumetric flow rate exceeds 9 scfm multiplied by the number of wet seals connected to the vent, the wet seals connected to the measured vent must be repaired as provided in paragraph (a)(8) of this section.

(A) For centrifugal compressors in operating-mode or in standby-pressurized-mode, determine volumetric flow rate at standard conditions from each centrifugal compressor on the Alaska North Slope equipped with a sour seal oil separator and capture system using one of the methods specified in paragraphs (a)(7)(ii)(A)(1) through (3) of this section.

(1) You may choose to use any of the methods set forth in § 60.5386b(a) to screen for leaks/emissions. For the purposes of this paragraph, when using any of the methods in § 60.5386b(a), emissions are detected whenever a leak is detected according to the method. If emissions are detected using the methods set forth in § 60.5386b(a), then you must use one of the methods specified in paragraph (a)(7)(ii)(A)(2) or (3) of this section to determine the volumetric flow rate. If emissions are not detected using the methods in § 60.5386b(a), then you may assume that the volumetric emissions are zero.

(2) Use a temporary or permanent flow meter according to methods set forth in § 60.5386b(b).

(3) Use a high-volume sampler according to the method set forth in § 60.5386b(c).

(B) For conducting measurements on manifolded groups of centrifugal compressors on the Alaska North Slope equipped with sour seal oil separators and capture systems, you must determine the volumetric flow rate from the centrifugal compressors equipped with sour seal oil separators and capture systems as specified in paragraph (a)(7)(ii)(B)(1) or (2) of this section.

(1) Measure at a single point in the manifold downstream of all centrifugal compressors on the Alaska North Slope equipped with sour seal oil separator and capture system wet seal inputs and, if practical, prior to comingling with other non-compressor emission sources.

(2) Determine the volumetric flow rate at standard conditions from the common stack using one of the methods specified in paragraph (a)(7)(ii)(A)(1) through (3) of this section.

(iii) You must determine the volumetric flow rate from your centrifugal compressor equipped with dry seals as specified in paragraph (a)(7)(iii)(A) or (B) of this section. If the volumetric flow rate exceeds 10 scfm multiplied by the number of dry seals connected to the vent, the dry seals connected to the measured vent must be repaired as provided in paragraph (a)(8) of this section.

(A) For centrifugal compressors equipped with dry seals in operating-mode or in standby-pressurized-mode, determine volumetric flow rate at standard conditions from each centrifugal

compressor equipped with dry seals using one of the methods specified in paragraphs (a)(7)(iii)(A)(1) through (3) of this section.

(1) You may choose to use any of the methods set forth in § 60.5386b(a) to screen for leaks/emissions. For the purposes of this paragraph, when using any of the methods in § 60.5386b(a), emissions are detected whenever a leak is detected according to the method. If emissions are detected using the methods set forth in § 60.5386b(a), then you must use one of the methods specified in paragraph (a)(7)(iii)(A)(2) or (3) of this section to determine the volumetric flow rate. If emissions are not detected using the methods in § 60.5386b(a), then you may assume that the volumetric emissions are zero.

(2) Use a temporary or permanent flow meter according to methods set forth in § 60.5386b(b).

(3) Use a high-volume sampler according to the method set forth in § 60.5386b(c).

(B) For conducting measurements on manifolded groups of centrifugal compressors equipped with dry seals, you must determine the volumetric flow rate from the dry seal centrifugal compressors as specified in paragraph (a)(7)(iii)(B)(1) or (2) of this section.

(1) Measure at a single point in the manifold downstream of all centrifugal compressors equipped with dry seals inputs and, if practical, prior to comingling with other non-compressor emission sources.

(2) Determine the volumetric flow rate at standard conditions from the common stack using one of the methods specified in paragraph (a)(7)(iii)(A)(1) through (3) of this section.

(8) The seal must be repaired within 90 calendar days after the date of the volumetric emissions measurement that exceeds the applicable required flow rate per seal. You must conduct follow-up volumetric flow rate measurements from seal vents using the methods specified in paragraph (a)(7) of this section within 15 days after the repair to document that the rate has been reduced to less than the applicable required flow rate per seal. If the individual seals are manifolded to a single open-ended vent line or vent, the volumetric flow rate must be reduced to less than the sum of the individual seals multiplied by the applicable required flow rate per seal specified in paragraph (a)(4) through (6) of this section, as applicable. Delay of repair will be allowed if the conditions in paragraphs (a)(8)(i) or (ii) of this section are met.

(i) If the repair of the wet or dry seal is technically infeasible, would require a vent blowdown, a compressor station shutdown, or would be unsafe to repair during operation of the unit, the repair must be completed during the next scheduled compressor station shutdown for maintenance, after a scheduled vent blowdown, or within 2 years of the date of the volumetric emissions measurement that exceeds the applicable required flow rate per seal, whichever is earliest. A vent blowdown is the opening of one or more blowdown valves to depressurize major production and processing equipment, other than a storage vessel.

(ii) If the repair requires replacement of the compressor seal or a part thereof, but the replacement cannot be acquired and installed within the repair timelines specified under this section due to the condition specified in paragraph (a)(8)(ii)(A) of this section, the repair must be completed in accordance with paragraph (a)(8)(ii)(B) of this section and documented in accordance with § 60.5420b(c)(4)(iii)(F) through (H).

(A) Seal or part thereof supplies had been sufficiently stocked but are depleted at the time of the required repair.

(B) The required replacement must be ordered no later than 10 calendar days after the centrifugal compressor seal is added to the delay of repair list due to parts unavailability. The repair must be completed as soon as practicable, but no later than 30 calendar days after receipt of the replacement seal or part, unless the repair requires a compressor station shutdown. If the repair requires a compressor station shutdown, the repair must be completed in accordance with the timeframe specified in paragraph (a)(8)(i) of this section.

(9) As an alternative to meeting the requirements for centrifugal compressors with dry seals specified in paragraphs (a)(6) through (8) of this section, owners or operators are allowed to comply with the standard by meeting the requirements specified in paragraphs (a)(9)(i) and (ii), or (a)(9)(iii) of this section.

(i) You must reduce methane and VOC emissions from each centrifugal compressor dry seal system by 95.0 percent.

(ii) If you use a control device to reduce emissions, you must equip the dry seal system with a cover that meets the requirements of § 60.5411b(b). The cover must be connected through a closed vent system that meets the requirements of § 60.5411b(a) and (c) and the closed vent system must be routed to a control device that meets the conditions specified in § 60.5412b.

(iii) As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process. If you route the emissions to a process, you must equip the dry seal system with a cover that meets the requirements of § 60.5411b(b). The cover must be connected through a closed vent system that meets the requirements of § 60.5411b(a) and (c).

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

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

(d) You must perform the reporting as required by § 60.5420b(b)(1) and (5), and (b)(11) through (13), as applicable; and the recordkeeping as required by § 60.5420b(c)(4), and (8) through (13), as applicable.

§ 60.5385b What GHG and VOC standards apply to reciprocating compressor affected facilities?

Each reciprocating compressor affected facility must comply with the GHG and VOC standards, using volumetric flow rate as a surrogate, in paragraphs (a) through (c) of this section, or the GHG and VOC standards in paragraph (d) of this section. You must also comply with the requirements in paragraphs (e) through (g) of this section.

(a) The volumetric flow rate of each cylinder, measured in accordance with paragraph (b) or (c) of this section, must not exceed 2 scfm per individual cylinder. If the individual cylinders are manifolded to a single open-ended vent line, the volumetric flow rate must not exceed the sum of the individual cylinders multiplied by 2 scfm. You must conduct measurements of the volumetric flow rate in accordance with the schedule specified in paragraphs (a)(1) and (2) of this section and determine the volumetric flow rate per cylinder in accordance with paragraph (b) or (c) of this section. If the volumetric flow rate, measured in accordance with paragraph (b) or (c) of this section, for a cylinder exceeds 2 scfm per cylinder (or a combined volumetric flow rate greater than the number of compression cylinders multiplied by 2 scfm), the rod packing or packings must be repaired or replaced as provided in paragraph (a)(3) of this section.

(1) You must conduct your first volumetric flow rate measurements from your reciprocating compressor rod packing vent on or before 8,760 hours of operation after May 7, 2024, or on or before 8,760 hours of operation after last rod packing replacement, or on or before 8,760 hours of operation after startup, whichever date is later.

(2) You must conduct subsequent volumetric flow rate measurements from your reciprocating compressor rod packing vent on or before 8,760 hours of operation after the previous measurement which demonstrates compliance with the applicable volumetric flow rate of 2 scfm per cylinder (or a combined volumetric flow rate greater than the number of compression cylinders multiplied by 2 scfm), or on or before 8,760 hours of operation after last rod packing replacement, whichever date is later.

(3) The rod packing must be repaired or replaced within 90 calendar days after the date of the volumetric emissions measurement that exceeded 2 scfm per cylinder. You must conduct follow-up volumetric flow rate measurements from compressor vents using the methods specified in paragraph (b) or (c) of this section within 15 days after the repair (or rod packing replacement) to document that the rate has been reduced to less than 2 scfm per cylinder. Delay of repair will be allowed if the conditions in paragraph (a)(3)(i) or (ii) of this section are met.

(i) If the repair (or rod packing replacement) is technically infeasible, would require a vent blowdown, a compressor station shutdown, or would be unsafe to repair during operation of the unit, the repair (or rod packing replacement) must be completed during the next scheduled compressor station shutdown for maintenance, after a scheduled vent blowdown, or within 2 years of the date of the volumetric emissions measurement that exceeds the applicable required flow rate per cylinder, whichever is earliest. A vent blowdown is the opening of one or more blowdown valves to depressurize major production and processing equipment, other than a storage vessel.

(ii) If the repair requires replacement of the rod packing or a part, but the replacement cannot be acquired and installed within the repair timelines specified under this section due to the condition specified in paragraph (a)(3)(ii)(A) of this section, the repair must be completed in accordance with paragraph (a)(3)(ii)(B) of this section and documented in accordance with § 60.5420b(c)(5)(viii) through (x).

(A) Rod packing or part supplies had been sufficiently stocked but are depleted at the time of the required repair.

(B) The required rod packing or part replacement must be ordered no later than 10 calendar days after the reciprocating compressor is added to the delay of repair list due to parts unavailability. The repair must be completed as soon as practicable, but no later than 30 calendar days after receipt of the replacement rod packing or part, unless the repair requires a compressor station shutdown. If the repair requires a compressor station shutdown, the repair must be completed in accordance with the timeframe specified in paragraph (a)(3)(i) of this section.

(b) You must determine the volumetric flow rate per cylinder from your reciprocating compressor as specified in paragraph (b)(1) or (2) of this section.

(1) For reciprocating compressor rod packing equipped with an open-ended vent line on compressors in operating or standby pressurized mode, determine the volumetric flow rate of the rod packing using one of the methods specified in paragraphs (b)(1)(i) through (iii) of this section.

(i) Determine the volumetric flow rate at standard conditions from the open-ended vent line using a high-volume sampler according to methods set forth in § 60.5386b(c).

(ii) Determine the volumetric flow rate at standard conditions from the open-ended vent line using a temporary or permanent meter, according to methods set forth in § 60.5386b(b).

(iii) Any of the methods set forth in § 60.5386b(a) to screen for leaks and emissions. For the purposes of this paragraph, emissions are detected whenever a leak is detected according to any of the methods in §

60.5386b(a). If emissions are detected using the methods set forth in § 60.5386b(a), then you must use one of the methods specified in paragraph (b)(1)(i) and (ii) of this section to determine the volumetric flow rate per cylinder. If emissions are not detected using the methods in § 60.5386b(a), then you may assume that the volumetric flow rate is zero.

(2) For reciprocating compressor rod packing not equipped with an open-ended vent line on compressors in operating or standby pressurized mode, you must determine the volumetric flow rate of the rod packing using the methods specified in paragraphs (b)(2)(i) and (ii) of this section.

(i) You must use the methods described in § 60.5386b(a) to conduct leak detection of emissions from the rod packing case into an open distance piece, or, for compressors with a closed distance piece, you must conduct annual leak detection of emissions from the rod packing vent, distance piece vent, compressor crank case breather cap, or other vent emitting gas from the rod packing.

(ii) You must measure emissions found in paragraph (b)(2)(i) of this section using a meter or high-volume sampler according to methods set forth in § 60.5386b(b) or (c).

(c) For conducting measurements on manifolded groups of reciprocating compressor affected facilities, you must determine the volumetric flow rate from reciprocating compressor rod packing vent as specified in paragraph (c)(1) and (2) of this section.

(1) Measure at a single point in the manifold downstream of all compressor vent inputs and, if practical, prior to comingling with other non-compressor emission sources.

(2) Determine the volumetric flow rate per cylinder at standard conditions from the common stack using one of the methods specified in paragraph (c)(2)(i) through (iv) of this section.

(i) A temporary or permanent flow meter according to the methods set forth in § 60.5386b(b).

(ii) A high-volume sampler according to methods set forth § 60.5386b(c).

(iii) An alternative method, as set forth in § 60.5386b(d).

(iv) Any of the methods set forth in § 60.5386b(a) to screen for emissions. For the purposes of this paragraph, emissions are detected whenever a leak is detected when using any of the methods in § 60.5386b(a). If emissions are detected using the methods set forth in § 60.5386b(a), then you must use one of the methods specified in paragraph (c)(2)(i) through (iii) of this section to determine the volumetric flow rate per cylinder. If emissions are not detected using the methods in § 60.5386b(a), then you may assume that the volumetric flow rate is zero.

(d) As an alternative to complying with the GHG and VOC standards in paragraphs (a) through (c) of this section, owners or operators can meet the requirements specified in paragraph (d)(1), (2), or (3) of this section.

(1) Collect the methane and VOC emissions from your reciprocating compressor rod packing using a rod packing emissions collection system that is operated to route the rod packing emissions to a process. In order to comply with this option, you must equip the reciprocating compressor with a cover that meets the requirements of § 60.5411b(b). The cover must be connected through a closed vent system that meets the requirements of § 60.5411b(a) and (c).

(2) Reduce methane and VOC emissions from each rod packing emissions collection system by using a control device that reduces methane and VOC emissions by 95.0 percent. In order to comply with this option, you must equip the reciprocating compressor with a cover that meets the requirements of § 60.5411b(b). The cover must be connected through a closed vent system that meets the requirements of § 60.5411b(a) and (c) and the closed vent system must be routed to a control device that meets the conditions specified in § 60.5412b.

(3) As an alternative to conducting the required volumetric flow rate measurements under paragraph (a) of this section, an owner or operator can choose to comply by replacing the rod packing on or before 8,760 hours of operation after startup, on or before 8,760 hours of operation after May 7, 2024, on or before 8,760 hours of operation after the previous flow rate measurement, or on or before 8,760 hours of operation after the date of the most recent compressor rod packing replacement, whichever date is later.

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

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

(g) You must perform the reporting requirements as specified in § 60.5420b(b)(1), (6), and (11) through (13), as applicable; and the recordkeeping requirements as specified in § 60.5420b(c)(5) and (8) through (13), as applicable.

§ 60.5386b What test methods and procedures must I use for my centrifugal compressor and reciprocating compressor affected facilities?

(a) You must use one of the methods described in paragraph (a)(1) and (2) of this section to screen for emissions or leaks from the reciprocating compressor rod packing when complying with § 60.5385b(b)(1)(iii) and from applicable wet seal centrifugal compressor and dry seal centrifugal compressor vents when complying with § 60.5380b(a)(3) through (6).

(1) *OGI instrument.* Use an OGI instrument for equipment leak detection as specified in either paragraph (a)(1)(i) or (ii) of this section. For the purposes of paragraphs (a)(1)(i) and (ii) of this section, any visible emissions observed by the OGI instrument from reciprocating rod packing or compressor dry or wet seal vent is a leak.

(i) *OGI instrument as specified in appendix K of this part.* For reciprocating compressor, applicable wet seal centrifugal compressor, and dry seal centrifugal compressor affected facilities located at onshore natural gas processing plants, use an OGI instrument to screen for emissions from reciprocating rod packing or centrifugal compressor dry seal vent in accordance with the protocol specified in appendix K of this part.

(ii) *OGI instrument as specified in § 60.5397b of this subpart.* For reciprocating compressor, applicable wet seal centrifugal compressor, and dry seal centrifugal compressor affected facilities located at centralized production facilities, compressor stations, or other location that is not an onshore natural gas processing plant, use an OGI instrument to screen for emissions from reciprocating rod packing or compressor dry seals in accordance with the elements of § 60.5397b(c)(7).

(2) *Method 21.* Use Method 21 in appendix A-7 to this part according to § 60.5403b(b)(1) and (2). For the purposes of this section, an instrument reading of 500 parts per million by volume (ppmv) above background or greater is a leak.

(b) You must determine natural gas volumetric flow rate using a rate meter which meets the requirement in Method 2D in appendix A-1 of this part. Rate meters must be calibrated on an annual basis according to the requirements in Method 2D.

(c) You must use a high-volume sampler to measure emissions of the reciprocating compressor rod packing, applicable centrifugal compressor wet seal vent, or centrifugal compressor dry seal vent in accordance with paragraphs (c)(1) through (7) of this section.

(1) You must use a high-volume sampler designed to capture the entirety of the emissions from the applicable vent and measure the entire range of methane concentrations being emitted as well as the total volumetric flow at standard conditions. You must develop a standard operating procedure for this device and document these

procedures in the appropriate monitoring plan. In order to get reliable results, persons using this device should be knowledgeable in its operation and the requirements in this section.

(2) This procedure may involve hazardous materials, operations, and equipment. This procedure may not address all of the safety problems associated with its use. It is the responsibility of the user of this procedure to establish appropriate safety and health practices and determine the applicability of regulatory limitations prior to performing this procedure.

(3) The high-volume sampler must include a methane gas sensor(s) which meets the requirements in paragraphs (c)(3)(i) through (iii) of this section.

(i) The methane sensor(s) must be selective to methane with minimal interference, less than 2.5 percent for the sum of responses to other compounds in the gas matrix. You must document the minimal interference through empirical testing or through data provided by the manufacturer of the sensor.

(ii) The methane sensor(s) must have a measurement range over the entire expected range of concentrations.

(iii) The methane sensor(s) must be capable of taking a measurement once every second, and the data system must be capable of recording these results for each sensor at all times during operation of the sampler.

(4) The high-volume sampler must be designed such that it is capable of sampling sufficient volume in order to capture all emissions from the applicable vent. Your high-volume sampler must include a flow measurement sensor(s) which meets the requirements of paragraphs (c)(4)(i) and (ii) of this section.

(i) The flow measurement sensor must have a measurement range over the entire expected range of flow rates sampled. If needed multiple sensors may be used to capture the entire range of expected flow rates.

(ii) The flow measurement sensor(s) must be capable of taking a measurement once every second, and the data system must be capable of recording these results for each sensor at all times during operation of the sampler.

(5) You must calibrate your methane sensor(s) according to the procedures in paragraphs (c)(5)(i)(A) and (B) of this section, and flow measurement sensors must be calibrated according to the procedures in paragraph (c)(5)(ii) of this section.

(i) For Methane Sensor Calibration:

(A) Initially and on a semi-annual basis, determine the linearity at four points through the measurement range for each methane sensor using methane gaseous calibration cylinder standards. At each point, the difference between the cylinder value and the sensor reading must be less than 5 percent of the respective calibration gas value. If the sensor does not meet this requirement, perform corrective action on the sensor, and do not use the sampler until these criteria can be met.

(B) Prior to and at the end of each testing day, challenge each sensor at two points, a low point, and a mid-point, using methane gaseous calibration cylinder standards. At each point, the difference between the cylinder value and the sensor reading must be less than 5 percent of the respective calibration gas value. If the sensor does not meet this requirement, perform corrective action on the sensor and do not use the sampler again until these criteria can be met. If the post-test calibration check fails at either point, invalidate the data from all tests performed subsequent to the last passing calibration check.

(ii) Flow measurement sensors must meet the requirements in Method 2D in appendix A-1 of this part. Rate meters must be calibrated on an annual basis according to the requirements in Method 2D. If your flow sensor relies on ancillary temperature and pressure measurements to correct the flow rate to standard conditions, the temperature and pressure sensors must also be calibrated on an annual basis. Standard conditions are defined as 20 °C (68 °F) and 760 mm Hg (29.92 in. Hg).

(6) You must conduct sampling of the reciprocating compressor rod packing, applicable wet seal centrifugal compressor, or dry seal centrifugal compressor vent in accordance with the procedures in paragraphs (c)(6)(i) through (v) of this section.

(i) The instrument must be operated consistent with manufacturer recommendations; users are encouraged to develop a standard operating procedure to document the exact procedures used for sampling.

(ii) Identify the rod packing, applicable wet seal centrifugal compressor, or dry seal centrifugal compressor vent to be measured and record the signal to noise ratio (S/N) of the engine. Collect a background methane sample in ppmv for a minimum of one minute and record the result along with the date and time.

(iii) Approach the vent with the sample hose and adjust the sampler so that you are measuring at the full flow rate. Then, adjust the flow rate to ensure the measured methane concentration is within the calibrated range of the methane sensor and minimum methane concentration is at least 2 ppmv higher than the background concentration. Sample for a period of at least one minute and record the average flow rate in standard cubic feet per minute and the methane sample concentration in ppmv, along with the date and time. Standard conditions are defined as 20 °C (68 °F) and 760 mm Hg (29.92 in. Hg).

(iv) Calculate the leak rate according to the following equation:

Equation 1 to paragraph (c)(6)(iv)

$$Q = V \left(\frac{CH4_S - CH4_B}{1000000} \right)$$

Where:

CH4_B = background methane concentration, ppmv

CH4_S = methane sample concentration, ppmv

V = Average flow rate of the sampler, scfm

Q = Methane emission rate, scfm

(v) You must collect at least three separate one-minute measurements and determine the average leak rate. The relative percent difference of these three separate samples should be less than 10 percent.

(7) If the measured natural gas flow determined as specified in paragraph (c)(6) of this section exceeds 70.0 percent of the manufacturer's reported maximum sampling flow rate you must either use a temporary or permanent flow meter according to paragraph (b) of this section or use another method meeting the requirements in paragraph (d) of this section to determine the leak or flow rate.

(d) As an alternative to a high-volume sampler, you may use any other method that has been validated in accordance with the procedures specified in Method 301 in appendix A in 40 CFR part 63, subject to Administrator approval, as specified in § 60.8(b).

§ 60.5390b What GHG and VOC standards apply to process controller affected facilities?

Each process controller affected facility must comply with the GHG and VOC standards in this section.

(a) Beginning January 22, 2027, or upon startup, whichever is later, you must design and operate each process controller affected facility with zero methane and VOC emissions to the atmosphere, except as provided in paragraph (b) of this section.

(1) If you comply by routing the emissions to a process, emissions must be routed to a process through a closed vent system.

(2) If you comply by using a self-contained natural gas-driven process controller, you must design and operate each self-contained natural gas-driven process controller with no identifiable emissions, as demonstrated by § 60.5416b(b).

(b) For each process controller affected facility located at a site in Alaska that does not have access to electrical power, you may comply with either paragraphs (b)(1) and (2) of this section or with paragraph (b)(3) of this section, instead of complying with paragraph (a) of this section.

(1) With the exception of natural gas-driven continuous bleed controllers that meet the condition in paragraph (b)(1)(i) of this section and that comply with paragraph (b)(1)(ii) of this section, each natural gas-driven continuous bleed process controller in the process controller affected facility must have a bleed rate less than or equal to 6 standard cubic feet per hour (scfh).

(i) A natural gas-driven continuous bleed process controller with a bleed rate higher than 6 scfh may be used if the requirements of paragraph (b)(1)(ii) of this section are met.

(ii) You demonstrate that a natural gas-driven continuous bleed controller with a bleed rate higher than 6 scfh is required. The demonstration must be based on the specific functional need, including but not limited to response time, safety, or positive actuation.

(2) Each natural gas-driven intermittent vent process controller in the process controller affected facility must comply with the requirements in paragraphs (b)(2)(i) and (ii) of this section.

(i) Each natural gas-driven intermittent vent process controller must not emit to the atmosphere during idle periods.

(ii) You must monitor each natural gas-driven intermittent vent process controller to ensure that it is not emitting to the atmosphere during idle periods, as specified in paragraphs (b)(2)(ii)(A) through (C) of this section.

(A) Monitoring must be conducted at the same frequency as specified for fugitive emissions components affected facilities located at the same type of site, as specified in § 60.5397b(g).

(B) You must include the monitoring of each natural gas-driven intermittent vent process controller in the monitoring plan required in § 60.5397b(b).

(C) When monitoring identifies emissions to the atmosphere from a natural gas-driven intermittent vent controller during idle periods, you must take corrective action by repairing or replacing the natural gas-driven intermittent vent process controller within 5 calendar days of the date the emissions to the atmosphere were detected. After the repair or replacement of a natural gas-driven intermittent vent process controller, you must re-survey the natural gas-

driven intermittent vent process controller within five days to verify that it is not venting emissions during idle periods.

(3) You must reduce methane and VOC emissions from all controllers in the process controller affected facility by 95.0 percent. You must route emissions through a closed vent system to a control device that meets the conditions specified in § 60.5412b.

(c) If you route process controller emissions to a process or a control device, you must route the process controller affected facility emissions through a closed vent system that meets the requirements of § 60.5411b(a) and (c).

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

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

(f) You must perform the reporting as required by § 60.5420b(b)(1), (7), and (11) through (13), as applicable, and the recordkeeping as required by § 60.5420b(c)(6), (8), and (10) through (13), as applicable.

§ 60.5393b What GHG and VOC standards apply to pump affected facilities?

Each pump affected facility must comply with the GHG and VOC standards in this section.

(a) For each pump affected facility meeting the criteria specified in paragraphs (a)(1) or (2) of this section, you must design and operate the pump affected facility with zero methane and VOC emissions to the atmosphere. If you comply by routing the pump affected facility emissions to a process, the emissions must be routed to the process through a closed vent system.

(1) The pump affected facility is located at a site that has access to electrical power.

(2) The pump affected facility is located at a site that does not have access to electrical power and has three or more natural gas-driven diaphragm pumps.

(b)

(1) For each pump affected facility located at a site that does not have access to electrical power and that also has fewer than three natural gas-driven diaphragm pumps, you must comply with paragraph (b)(2) or (3) of this section, except as provided in paragraphs (b)(4) through (8) of this section.

(2) Emissions from the pump affected facility must be routed through a closed vent system to a process if a vapor recovery unit is onsite.

(3) If a vapor recovery unit is not onsite, you must reduce methane and VOC emissions from the pump affected facility by 95.0 percent. You must route affected pump facility emissions through a closed vent system to a control device meeting the conditions specified in § 60.5412b.

(4) You are not required to install an emissions control device or a vapor recovery unit, if such a unit is necessary to enable emissions to be routed to a process, solely for the purpose of complying with the requirements of paragraph (b)(2) or (3) of this section. If no control device capable of achieving a 95.0 percent emissions reduction and no vapor recovery unit is present on site, you must comply with paragraph (b)(5) or (6) of this section, as applicable. For the purposes of this section, boilers and process heaters are not considered to be control devices.

(5) If an emissions control device is on site but is unable to achieve a 95.0 percent emissions reduction, you must route the pump affected facility emissions through a closed vent system to that control device. You must certify that there is no vapor recovery unit on site and that there is no control device capable of achieving a 95.0 percent emissions reduction on site.

(6) If there is no vapor recovery unit on site and no emission control device is on site, you must certify that there is no vapor recovery unit or emissions control device on site. If you subsequently install a control device or vapor recovery unit, you must meet the requirements of paragraphs (b)(6)(i) and (ii) of this section.

(i) You must be in compliance with the requirements of paragraphs (b)(1) through (3) of this section, as applicable, within 30 days of startup of the control device or vapor recovery unit.

(ii) You must maintain the records in § 60.5420b(c)(15)(ii) through (iv), as applicable. You are no longer required to maintain the records in § 60.5420b(c)(15)(v) certifying that there is no vapor recovery unit or control device on site.

(7) If an owner or operator complying with paragraph (b)(1) of this section determines, through an engineering assessment, that routing the pump affected facility emissions to a control device or to a process is technically infeasible, the requirements specified in paragraphs (b)(7)(i) through (iii) of this section must be met.

(i) The owner or operator must conduct the assessment of technical infeasibility in accordance with the criteria in paragraph (b)(7)(ii) of this section and have it certified by either a qualified professional engineer or an in-house engineer with expertise on the design and operation of the pump affected facility and the control device or processes at the site in accordance with paragraph (b)(7)(iii) of this section.

(ii) The assessment of technical infeasibility to route emissions from the pump affected facility to an existing control device or process must include, but is not limited to, safety considerations, distance from the control device or process, pressure losses and differentials in the closed vent system, and the ability of the control device or process to handle the pump affected facility emissions which are routed to them. The assessment of technical infeasibility must be prepared under the direction or supervision of the qualified professional engineer or in-house engineer who signs the certification in accordance with paragraph (b)(7)(iii) of this section.

(iii) The following certification, signed and dated by the qualified professional engineer or in-house engineer, must state: "I certify that the assessment of technical infeasibility was prepared under my direction or supervision. I further certify that the assessment was conducted and this report was prepared pursuant to the requirements of § 60.5393b(b)(7)(ii). Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete."

(8) If the pump affected facility emissions are routed to a control device or process and the control device or process is subsequently removed from the location or is no longer available, such that there is no option to route to a control device or process, you are no longer required to be in compliance with the requirements of paragraphs (b)(2) or (3) of this section, and instead must comply with paragraph (b)(6) of this section.

(c) If you use a control device or route to a process to reduce emissions, you must route the pump affected facility emissions through a closed vent system that meets the requirements of § 60.5411b(a) and (c).

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

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

(f) You must perform the reporting as required by § 60.5420b(b)(1), (10), and (11) through (13), as applicable; and the recordkeeping as required by § 60.5420b(c)(8), (10) through (13), and (15), as applicable.

§ 60.5395b What GHG and VOC standards apply to storage vessel affected facilities?

Each storage vessel affected facility must comply with the GHG and VOC standards in this section, except as provided in paragraph (e) of this section.

(a) *General requirements.* You must comply with the requirements of paragraphs (a)(1) and (2) of this section. After 12 consecutive months of compliance with paragraph (a)(2) of this section, you may continue to comply with paragraph (a)(2) of this section, or you may comply with paragraph (a)(3) of this section, if applicable. If you choose to meet the requirements of paragraph (a)(3) of this section, you are not required to comply with the requirements of paragraph (a)(2) of this section except as provided in paragraphs (a)(3)(i) and (ii) of this section.

(1) Determine the potential for methane and VOC emissions in accordance with § 60.5365b(e)(2).

(2) Reduce methane and VOC emissions by 95.0 percent.

(3) Maintain the uncontrolled actual VOC emissions at less than 4 tpy and the actual methane emissions at less than 14 tpy from the storage vessel affected facility without considering control. Prior to using the uncontrolled actual VOC and methane emission rates for compliance purposes, you must demonstrate that the uncontrolled actual VOC emissions have remained less than 4 tpy and the uncontrolled actual methane emissions have remained less than 14 tpy as determined monthly for 12 consecutive months. After such demonstration, you must determine the uncontrolled actual rolling 12-month determination VOC and methane emissions rates each month. The uncontrolled actual VOC and methane emissions must be calculated using a generally accepted model or calculation methodology which account for flashing, working and breathing losses, and the calculations must be based on the actual average throughput, temperature, and separator pressure for the month. You may no longer comply with this paragraph and must instead comply with paragraph (a)(2) of this section if your storage vessel affected facility meets the conditions specified in paragraphs (a)(3)(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 (a)(2) 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 rolling 12-month emissions determination required in this section indicates that VOC emissions increase to 4 tpy or greater or the methane emissions increase to 14 tpy or greater from your storage vessel affected facility and the increase is not associated with fracturing or refracturing of a well feeding the storage vessel affected facility, you must comply with paragraph (a)(2) of this section within 30 days of the monthly determination.

(b) *Control requirements.*

(1) Except as required in paragraph (b)(2) of this section, if you use a control device to reduce methane and VOC emissions from your storage vessel affected facility, you must meet all of the design and operational criteria specified in paragraphs (b)(1)(i) through (iii) of this section.

(i) Each storage vessel in the tank battery must be equipped with a cover that meets the requirements of § 60.5411b(b);

(ii) The tank battery must be equipped with one or more closed vent system that meets the requirements of § 60.5411b(a) and (c); and

(iii) The vapors collected in paragraphs (b)(1)(ii) of this section must be routed to a control device that meets the conditions specified in § 60.5412b. As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(2) For storage vessel affected facilities that do not have flashing emissions and that are not located at well sites or centralized production facilities, you may use a floating roof to reduce emissions. 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 subpart Kb of this part. You must submit a statement that you are complying with § 60.112b(a)(1) or (2) with the initial annual report specified in § 60.5420b(b)(1) and (8).

(c) *Requirements for storage vessel affected facilities that are removed from service or returned to service.* If you remove a storage vessel affected facility from service or remove a portion of a storage vessel affected facility from service, you must comply with the applicable paragraphs (c)(1) through (4) of this section. A storage vessel is not an affected facility under this subpart for the period that it is removed from service.

(1) For a storage vessel affected facility to be removed from service, you must comply with the requirements of paragraphs (c)(1)(i) and (ii) of this section.

(i) You must completely empty and degas each storage vessel, such that each storage vessel no longer contains crude oil, condensate, produced water or intermediate hydrocarbon liquids. A storage vessel where liquid is left on walls, as bottom clingage or in pools due to floor irregularity is considered to be completely empty.

(ii) You must submit a notification as required in § 60.5420b(b)(8)(vii) in your next annual report, identifying each storage vessel affected facility removed from service during the reporting period and the date of its removal from service.

(2) For a portion of a storage vessel affected facility to be removed from service, you must comply with the requirements of paragraphs (c)(2)(i) through (iv) of this section.

(i) You must completely empty and degas the storage vessel(s), such that the storage vessel(s) no longer contains crude oil, condensate, produced water or intermediate hydrocarbon liquids. A storage vessel where liquid is left on walls, as bottom clingage or in pools due to floor irregularity is considered to be completely empty.

(ii) You must disconnect the storage vessel(s) from the tank battery by isolating the storage vessel(s) from the tank battery such that the storage vessel(s) is no longer manifolded to the tank battery by liquid or vapor transfer.

(iii) You must submit a notification as required in § 60.5420b(b)(8)(vii) in your next annual report, identifying each storage vessel removed from service during the reporting period, the impacted storage vessel affected facility, and the date of its removal from service.

(iv) The remaining storage vessel(s) in the tank battery remain a storage vessel affected facility and must continue to comply with the applicable requirements of paragraphs (a) and (b) of this section.

(3) If a storage vessel identified in paragraph (c)(1)(ii) or (c)(2)(iii) of this section is returned to service, you must determine its affected facility status as provided in § 60.5365b(e)(6).

(4) For each storage vessel affected facility or portion of a storage vessel affected facility returned to service during the reporting period, you must submit a notification in your next annual report as required in § 60.5420b(b)(8)(viii), identifying each storage vessel affected facility or portion of a storage vessel affected facility and the date of its return to service.

(d) *Compliance, notification, recordkeeping, and reporting.* You must comply with paragraphs (d)(1) through (3) of this section.

(1) You must demonstrate initial compliance with standards as required by § 60.5410b(j).

(2) You must demonstrate continuous compliance with standards as required by § 60.5415b(i).

(3) You must perform the required reporting as required by § 60.5420b(b)(1) and (8) and (b)(11) through (13), as applicable; and the recordkeeping as required by § 60.5420b(c)(7) and (c)(8) through (13), as applicable.

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

§ 60.5397b What GHG and VOC standards apply to fugitive emissions components affected facilities?

This section applies to fugitive emissions components affected facilities. You must comply with the requirements of paragraphs (a) through (l) of this section to reduce fugitive emissions of methane and VOC. The requirements of this section are independent of the cover and closed vent system requirements of § 60.5411b.

(a) *General requirements.* You must monitor all fugitive emissions components affected facilities in accordance with paragraphs (b) through (g) of this section. You must repair all sources of fugitive emissions in accordance with paragraph (h) of this section. You must demonstrate initial compliance in accordance with paragraph (i) of this section. You must keep records in accordance with paragraph (j) of this section and report in accordance with paragraph (k) of this section. You must meet the requirements for well closures in accordance with paragraph (l) of this section.

(b) *Develop fugitive emissions monitoring plan.* You must develop a fugitive emissions monitoring plan that covers all fugitive emissions components affected facilities within each company-defined area in accordance with paragraphs (c) and (d) of this section.

(c) *Elements of fugitive emissions monitoring plan.* Your fugitive emissions monitoring plan must include the elements specified in paragraphs (c)(1) through (8) of this section, at a minimum.

(1) Frequency for conducting surveys. Surveys must be conducted at least as frequently as required by paragraphs (f) and (g) of this section.

(2) Technique for determining fugitive emissions (*i.e.*, AVO or other detection methods, Method 21 of appendix A-7 to this part, and/or OGI and meeting the requirements of paragraphs (c)(7)(i) through (vii) of this section).

(3) Manufacturer and model number of fugitive emissions detection equipment to be used, if applicable.

(4) Procedures and timeframes for identifying and repairing fugitive emissions components from which fugitive emissions are detected, including timeframes for fugitive emission components that are unsafe to repair. Your repair schedule must meet the requirements of paragraph (h) of this section at a minimum.

(5) Procedures and timeframes for verifying fugitive emission component repairs.

(6) Records that will be kept and the length of time records will be kept.

(7) If you are using OGI, your plan must also include the elements specified in paragraphs (c)(7)(i) through (vii) of this section.

(i) Verification that your OGI equipment meets the specifications of paragraphs (c)(7)(i)(A) and (B) of this section. This verification is an initial verification, and may either be performed by the facility, by the manufacturer, or by a third party. For the purposes of complying with the fugitive emissions monitoring program with OGI, fugitive emissions are defined as any visible emissions observed using OGI.

(A) Your OGI equipment must be capable of imaging gases in the spectral range for the compound of highest concentration in the potential fugitive emissions.

(B) Your OGI equipment must be capable of imaging a gas that is half methane, half propane at a concentration of 10,000 ppm at a flow rate of ≤60 g/hr from a quarter inch diameter orifice.

(ii) Procedure for a daily verification check.

(iii) Procedure for determining the operator's maximum viewing distance from the equipment and how the operator will ensure that this distance is maintained.

(iv) Procedure for determining maximum wind speed during which monitoring can be performed and how the operator will ensure monitoring occurs only at wind speeds below this threshold.

(v) Procedures for conducting surveys, including the items specified in paragraphs (c)(7)(v)(A) through (C) of this section.

(A) How the operator will ensure an adequate thermal background is present in order to view potential fugitive emissions.

(B) How the operator will deal with adverse monitoring conditions, such as wind.

(C) How the operator will deal with interferences (e.g., steam).

(vi) Training and experience needed prior to performing surveys.

(vii) Procedures for calibration and maintenance. At a minimum, procedures must comply with those recommended by the manufacturer.

(8) If you are using Method 21 of appendix A-7 to this part, your plan must also include the elements specified in paragraphs (c)(8)(i) through (iv) of this section. For the purposes of complying with the fugitive emissions monitoring program using Method 21 of appendix A-7 to this part a fugitive emission is defined as an instrument reading of 500 ppmv or greater.

(i) *Verification that your monitoring equipment meets the requirements specified in Section 6.0 of Method 21 of appendix A-7 to this part.* For purposes of instrument capability, the fugitive emissions definition shall be 500 ppmv or greater methane using a FID-based instrument. If you wish to use an analyzer other than an FID-based instrument, you must develop a site-specific fugitive emission definition that would be equivalent to 500 ppmv methane using a FID-based instrument (e.g., 10.6 eV PID with a specified isobutylene concentration as the fugitive emission definition would provide equivalent response to your compound of interest).

(ii) *Procedures for conducting surveys.* At a minimum, the procedures shall ensure that the surveys comply with the relevant sections of Method 21 of appendix A-7 to this part, including Section 8.3.1.

(iii) *Procedures for calibration.* The instrument must be calibrated before use each day of its use by the procedures specified in Method 21 of appendix A-7 to this part. At a minimum, you must also conduct precision tests at the interval specified in Method 21 of appendix A-7 to this part, Section 8.1.2, and a calibration drift assessment at the end of each monitoring day. The calibration drift assessment must be conducted as specified in paragraph (c)(8)(iii)(A) of this section. Corrective action for drift assessments is specified in paragraphs (c)(8)(iii)(B) and (C) of this section.

(A) Check the instrument using the same calibration gas that was used to calibrate the instrument before use. Follow the procedures specified in Method 21 of appendix A-7 to this part, Section 10.1, except do not adjust the meter readout to correspond to the calibration gas value. If multiple scales are used, record the instrument reading for each scale used. Divide the arithmetic difference of the initial and post-test calibration response by the corresponding calibration gas value for each scale and multiply by 100 to express the calibration drift as a percentage.

(B) If a calibration drift assessment shows a negative drift of more than 10 percent, then all equipment with instrument readings between the fugitive emission definition multiplied by (100

minus the percent of negative drift) divided by 100 and the fugitive emission definition that was monitored since the last calibration must be re-monitored.

(C) If any calibration drift assessment shows a positive drift of more than 10 percent from the initial calibration value, then, at the owner/operator's discretion, all equipment with instrument readings above the fugitive emission definition and below the fugitive emission definition multiplied by (100 plus the percent of positive drift) divided by 100 monitored since the last calibration may be re-monitored.

(iv) *Procedures for monitoring yard piping (other than buried yard piping).* At a minimum, place the probe inlet at the surface of the yard piping and run the probe down the length of the piping. Connection points on the piping must be monitored following the procedures specified in Method 21 of appendix A-7 to this part.

(d) *Additional elements of fugitive emissions monitoring plan.* Each fugitive emissions monitoring plan must include the elements specified in paragraphs (d)(1) and (2) of this section, at a minimum, as applicable.

(1) If you are using OGI, your plan must include procedures to ensure that all fugitive emissions components, except buried yard piping and associated components (*e.g.*, connectors), are monitored during each survey. Example procedures include, but are not limited to, a sitemap with an observation path, a written narrative of where the fugitive emissions components are located and how they will be monitored, or an inventory of fugitive emissions components.

(2) If you are using Method 21 of appendix A-7 to this part, your plan must include a list of fugitive emissions components to be monitored and method for determining the location of fugitive emissions components to be monitored in the field (*e.g.*, tagging, identification on a process and instrumentation diagram, etc.). Your fugitive emissions monitoring plan must include the written plan developed for all of the fugitive emissions components designated as difficult-to-monitor in accordance with paragraph (g)(2) of this section, and the written plan for fugitive emissions components designated as unsafe-to-monitor in accordance with paragraph (g)(3) of this section.

(e) *Monitoring of fugitive emissions components.* Each fugitive emissions component, except buried yard piping and associated components (*e.g.*, connectors), shall be observed or monitored for fugitive emissions during each monitoring survey.

(f) *Initial monitoring survey.* You must conduct initial monitoring surveys according to the requirements specified in paragraphs (f)(1) through (4) of this section.

(1) At single wellhead only sites and small sites, you must conduct an initial monitoring survey using audible, visual, and olfactory (AVO), or any other detection methods (*e.g.*, OGI), within 90 days of the startup of production, for each fugitive emissions components affected facility or by June 6, 2024 whichever date is later.

(2) For multi-wellhead only well sites, well sites or centralized production facilities that contain the major production and processing equipment specified in paragraphs (g)(1)(iv)(A), (B), (C), or (D) of this section, and compressor station sites, you must conduct an initial monitoring survey using OGI or Method 21 of appendix A-7 to this part within 90 days of the startup of production, for each fugitive emissions components affected facility or by June 6, 2024 whichever date is later.

(3) For a modified or reconstructed fugitive emissions components affected facility, the initial monitoring survey must be conducted within 90 days of the startup of production for each fugitive emissions components affected facility after the modification or reconstruction or by June 6, 2024, whichever date is later.

(4) Notwithstanding the deadlines specified in paragraphs (f)(1) through (3) of this section, for each fugitive emissions components affected facility located on the Alaskan North Slope that starts up production between

September and March, you must conduct an initial monitoring survey within 6 months of the startup of production for a new well site, within 6 months of the first day of production after a modification of the fugitive emissions components affected facility, or by the following June 30, whichever date is latest.

(g) *Monitoring frequency.* A monitoring survey of each fugitive emissions components affected facility must be performed as specified in paragraph (g)(1) of this section, with the exceptions noted in paragraphs (g)(2) through (4) of this section. Monitoring for fugitive emissions components affected facilities located at well sites and centralized production facilities that have wells located onsite must continue at the specified frequencies in paragraphs (g)(1)(i), (ii), (iii), (iv) and (vi) of this section until the well closure requirements of paragraph (l) of this section are completed.

(1) A monitoring survey of the fugitive emissions components affected facilities must be conducted using the methods and at the frequencies specified in paragraphs (g)(1)(i) through (vi) of this section.

(i) A monitoring survey of the fugitive emissions component affected facilities located at single wellhead only well sites must be conducted at least quarterly using AVO, or any other detection method, after the initial survey except as specified in paragraph (g)(1)(vi) of this section. Any indications of fugitive emissions using these methods are considered fugitive emissions that must be repaired in accordance with paragraph (h) of this section.

(ii) A monitoring survey of the fugitive emissions component affected facilities located at small well sites must be conducted at least quarterly using AVO, or any other detection method, after the initial survey except as specified in paragraph (g)(1)(vi) of this section. Any indications of fugitive emissions using these methods are considered fugitive emissions that must be repaired in accordance with paragraph (h) of this section. At small well sites with an uncontrolled storage vessel, a visual inspection of all thief hatches and other openings on the storage vessel that are fugitive emissions components must be conducted in conjunction with the monitoring survey to ensure that they are kept closed and sealed at all times except during times of adding or removing material, inspecting or sampling material, or during required maintenance operations. If evidence of a deviation from this requirement is found, you must take corrective action. At small well sites with a separator, a visual inspection of all separator dump valves to ensure the dump valve is free of debris and not stuck in an open position must be conducted in conjunction with the monitoring survey. Any dump valve not operating as designed must be repaired.

(iii) A monitoring survey of the fugitive emissions components affected facilities located at multi-wellhead only well sites must be conducted in accordance with paragraphs (g)(1)(iii)(A) and (B) of this section, except as specified in paragraph (g)(1)(vi) of this section.

(A) A monitoring survey must be conducted at least quarterly using AVO, or any other detection method, after the initial survey. Any indications of fugitive emissions using these methods are considered fugitive emissions that must be repaired in accordance with paragraph (h) of this section.

(B) A monitoring survey must be conducted at least semiannually using OGI or Method 21 of appendix A-7 to this part after the initial survey. Consecutive semiannual surveys must be conducted at least 4 months apart and no more than 7 months apart.

(iv) A monitoring survey of the fugitive emissions components affected facilities located at well sites or centralized production facilities that contain the major production and processing equipment specified in paragraphs (g)(1)(iv)(A), (B), (C), or (D) must be conducted at the frequencies in paragraphs (g)(1)(iv)(E) and (F) of this section, except as specified in paragraph (g)(1)(vi) of this section.

(A) One or more controlled storage vessels or tank batteries.

(B) One or more control devices.

(C) One or more natural gas-driven process controllers or pumps.

(D) Two or more pieces of major production and processing equipment not specified in paragraphs (g)(1)(iv)(A) through (C) of this section.

(E) A monitoring survey must be conducted at least bimonthly using AVO, or any other detection method, after the initial survey. Any indications of fugitive emissions using these methods are considered fugitive emissions that must be repaired in accordance with paragraph (h) of this section. A visual inspection of all thief hatches and other openings on storage vessels (or tank batteries) that are fugitive emissions components must be conducted in conjunction with the monitoring survey to ensure that they are kept closed and sealed at all times except during times of adding or removing material, inspecting or sampling material, or during required maintenance operations. If evidence of a deviation from this requirement is found, you must take corrective action. A visual inspection must be conducted of all separator dump valves to ensure the dump valve is free of debris and not stuck in an open position must be conducted in conjunction with the monitoring survey. Any dump valve not operating as designed must be repaired.

(F) A monitoring survey must be conducted at least quarterly using OGI or Method 21 of appendix A-7 to this part after the initial survey. Consecutive quarterly monitoring surveys must be conducted at least 60 calendar days apart.

(v) A monitoring survey of the fugitive emissions components affected facility located at a compressor station must be conducted at the frequencies in paragraphs (g)(1)(v)(A) and (B) of this section, except as specified in paragraph (g)(1)(vi) of this section,

(A) A monitoring survey must be conducted at least monthly using AVO, or any other detection method, after the initial survey. Any indications of fugitive emissions using these methods are considered fugitive emissions that must be repaired in accordance with paragraph (h) of this section.

(B) A monitoring survey must be conducted at least quarterly using OGI or Method 21 of appendix A-7 to this part after the initial survey. Consecutive quarterly monitoring surveys must be conducted at least 60 calendar days apart.

(vi) A monitoring survey of the fugitive emissions components affected facility located on the Alaska North Slope must be conducted using OGI of this part or Method 21 of appendix A-7 to this part at least annually. Consecutive annual monitoring surveys must be conducted at least 9 months apart and no more than 13 months apart.

(2) If you are using Method 21 of appendix A-7 to this part, fugitive emissions components that cannot be monitored without elevating the monitoring personnel more than 2 meters above the surface may be designated as difficult-to-monitor. Fugitive emissions components that are designated difficult-to-monitor must meet the specifications of paragraphs (g)(2)(i) through (iv) of this section.

(i) A written plan must be developed for all the fugitive emissions components designated difficult-to-monitor. This written plan must be incorporated into the fugitive emissions monitoring plan required by paragraphs (b), (c), and (d) of this section.

(ii) The plan must include the identification and location of each fugitive emissions component designated as difficult-to-monitor.

(iii) The plan must include an explanation of why each fugitive emissions component designated as difficult-to-monitor is difficult-to-monitor.

(iv) The plan must include a schedule for monitoring the difficult-to-monitor fugitive emissions components at least once per calendar year.

(3) If you are using Method 21 of appendix A-7 to this part, fugitive emissions components that cannot be monitored because monitoring personnel would be exposed to immediate danger while conducting a monitoring survey may be designated as unsafe-to-monitor. Fugitive emissions components that are designated unsafe-to-monitor must meet the specifications of paragraphs (g)(3)(i) through (iv) of this section.

(i) A written plan must be developed for all the fugitive emissions components designated unsafe-to-monitor. This written plan must be incorporated into the fugitive emissions monitoring plan required by paragraphs (b), (c), and (d) of this section.

(ii) The plan must include the identification and location of each fugitive emissions component designated as unsafe-to-monitor.

(iii) The plan must include an explanation of why each fugitive emissions component designated as unsafe-to-monitor is unsafe-to-monitor.

(iv) The plan must include a schedule for monitoring the fugitive emissions components designated as unsafe-to-monitor.

(4) The requirements of paragraphs (g)(1)(iv)(F) and (g)(1)(v)(B) of this section are waived during a quarterly monitoring period for any fugitive emissions components affected facility located within an area that has an average calendar month temperature below 0 degrees Fahrenheit for two of three consecutive calendar months of a quarterly monitoring period. The calendar month temperature average for each month within the quarterly monitoring period must be determined using historical monthly average temperatures over the previous three years as reported by a National Oceanic and Atmospheric Administration source or other source approved by the Administrator. The requirements of paragraph (g)(1)(iv) and (v) of this section shall not be waived for two consecutive quarterly monitoring periods.

(h) *Repairs.* Each identified source of fugitive emissions shall be repaired in accordance with paragraphs (h)(1) and (2) of this section.

(1) A first attempt at repair shall be made in accordance with paragraphs (h)(1)(i) and (ii) of this section.

(i) A first attempt at repair shall be made no later than 15 calendar days after detection of fugitive emissions that were identified using AVO.

(ii) If you are complying with paragraph (g)(1)(i) through (vi) of this section using OGI or Method 21 of appendix A-7 to this part, a first attempt at repair shall be made no later than 30 calendar days after detection of the fugitive emissions.

(2) Repair shall be completed as soon as practicable, but no later than 15 calendar days after the first attempt at repair as required in paragraph (h)(1)(i) of this section, and 30 calendar days after the first attempt at repair as required in paragraph (h)(1)(ii) of this section.

(3) Delay of repair will be allowed if the conditions in paragraphs (h)(3)(i) or (ii) of this section are met.

(i) If the repair is technically infeasible, would require a vent blowdown, a compressor station shutdown, a well shutdown or well shut-in, or would be unsafe to repair during operation of the unit, the repair must be completed during the next scheduled compressor station shutdown for maintenance, scheduled well shutdown, scheduled well shut-in, after a scheduled vent blowdown, or within 2 years of detecting the fugitive emissions, whichever is earliest. A vent blowdown is the opening of one or more

blowdown valves to depressurize major production and processing equipment, other than a storage vessel.

(ii) If the repair requires replacement of a fugitive emissions component or a part thereof, but the replacement cannot be acquired and installed within the repair timelines specified in paragraphs (h)(1) and (2) of this section due to either of the conditions specified in paragraph (h)(3)(ii)(A) or (B) of this section, the repair must be completed in accordance with paragraph (h)(3)(ii)(C) of this section and documented in accordance with § 60.5420b(c)(14)(v)(I).

(A) Valve assembly supplies had been sufficiently stocked but are depleted at the time of the required repair.

(B) A replacement fugitive emissions component or a part thereof requires custom fabrication.

(C) The required replacement must be ordered no later than 10 calendar days after the first attempt at repair. The repair must be completed as soon as practicable, but no later than 30 calendar days after receipt of the replacement component, unless the repair requires a compressor station or well shutdown. If the repair requires a compressor station or well shutdown, the repair must be completed in accordance with the timeframe specified in paragraph (h)(3)(i) of this section.

(4) Each identified source of fugitive emissions must be resurveyed to complete repair according to the requirements of paragraphs (h)(4)(i) through (v) of this section, to ensure that there are no fugitive emissions.

(i) The operator may resurvey the fugitive emissions components to verify repair using either Method 21 of appendix A-7 to this part or OGI, except as specified in paragraph (h)(4)(v) of this section.

(ii) For each repair that cannot be made during the monitoring survey when the fugitive emissions are initially found, a digital photograph must be taken of that component, or the component must be tagged during the monitoring survey when the fugitive emissions were initially found for identification purposes and subsequent repair. The digital photograph must include the date that the photograph was taken and must clearly identify the component by location within the site (*e.g.*, the latitude and longitude of the component or by other descriptive landmarks visible in the picture).

(iii) Operators that use Method 21 of appendix A-7 to this part to resurvey the repaired fugitive emissions components are subject to the resurvey provisions specified in paragraphs (h)(4)(iii)(A) and (B) of this section.

(A) A fugitive emissions component is repaired when the Method 21 instrument indicates a concentration of less than 500 ppmv above background or when no soap bubbles are observed when the alternative screening procedures specified in section 8.3.3 of Method 21 of appendix A-7 to this part are used.

(B) Operators must use the Method 21 monitoring requirements specified in paragraph (c)(8)(ii) of this section or the alternative screening procedures specified in section 8.3.3 of Method 21 of appendix A-7 to this part.

(iv) Operators that use OGI to resurvey the repaired fugitive emissions components are subject to the resurvey provisions specified in paragraphs (h)(4)(iv)(A) and (B) of this section.

(A) A fugitive emissions component is repaired when the OGI instrument shows no indication of visible emissions.

(B) Operators must use the OGI monitoring requirements specified in paragraph (c)(7) of this section.

(v) For fugitive emissions identified using AVO detection methods, the operator may resurvey using those same methods, Method 21 of appendix A-7 to this part, or OGI. For operators that use AVO detection methods, a fugitive emissions component is repaired when there are no indications of fugitive emissions using these methods.

(i) *Initial compliance.* You must demonstrate initial compliance with the standards that apply to fugitive emissions components affected facilities as required by § 60.5410b(k).

(j) *Continuous compliance.* You must demonstrate continuous compliance with the standards that apply to fugitive emissions components affected facilities as required by § 60.5415b(l).

(k) *Reporting and recordkeeping.* You must comply with the reporting requirements as specified in § 60.5420b(b)(1) and (9), and the recordkeeping requirements as specified in § 60.5420b(c)(14).

(l) *Well closure requirements.* You must complete the requirements specified in paragraphs (l)(1) through (4) of this section.

(1) You must submit a well closure plan to the Administrator within 30 days of the cessation of production from all wells located at the well site as specified in § 60.5420b(a)(4)(i). The well closure plan must include, at a minimum, the information specified in paragraphs (l)(1)(i) through (iii) of this section.

(i) Description of the steps necessary to close all wells at the well site, including permanent plugging of all wells;

(ii) Description of the financial requirements and disclosure of financial assurance to complete closure; and

(iii) Description of the schedule for completing all activities in the well closure plan.

(2) You must submit a notification as specified in § 60.5420b(a)(4)(ii) of intent to close the well site to the Administrator 60 days before you begin well closure activities.

(3) You must conduct a survey of the well site using OGI, including each closed well, after completing all well closure activities outlined in the well closure plan specified in paragraph (l)(1) of this section. If any emissions are imaged by the OGI instrument, then you must take steps to eliminate those emissions and you must resurvey the source of emissions. You must repeat steps to eliminate emissions and resurvey the source of emissions until no emissions are imaged by the OGI instrument. You must update the well closure plan specified in paragraph (l)(1) of this section to include the video of the OGI survey demonstrating closure of all wells at the site.

(4) You must maintain the records specified in § 60.5420b(c)(14) and submit the reports specified in § 60.5420b(b)(9).

§ 60.5398b What alternative GHG and VOC standards apply to fugitive emissions components affected facilities and what inspection and monitoring requirements apply to covers and closed vent systems when using an alternative technology?

This section provides alternative GHG and VOC standards for fugitive emissions components affected facilities in § 60.5397b and alternative continuous inspection and monitoring requirements for covers and closed vent systems in § 60.5416b(a)(1)(ii) and (iii), (2)(ii) through (iv), and (3)(iii) and (iv). If you choose to use an alternative standard under this section, you must submit the notification under paragraph (a) of this section. If you choose to demonstrate compliance with the alternative GHG and VOC standards through periodic screening, you are subject to the requirements in paragraph (b) of this section. If you choose to demonstrate compliance through a continuous monitoring system, you are subject to the requirements in paragraph (c) of this section. The technology used for periodic screenings under

paragraph (b) of this section or continuous monitoring under paragraph (c) of this section must be approved in accordance with paragraph (d) of this section.

(a) *Notification.* If you choose to demonstrate compliance with the alternative GHG and VOC standards in either paragraph (b) or (c) of this section, you must notify the Administrator of adoption of the alternative standards in the first annual report following implementation of the alternative standards, as specified in § 60.5424b(a). Once you have implemented the alternative standards, you must continue to comply with the alternative standards.

(b) *Periodic Screening.* You may choose to demonstrate compliance for your fugitive emissions components affected facility and compliance with continuous inspection and monitoring requirements for your covers and closed vent systems through periodic screenings using any methane measurement technology approved in accordance with paragraph (d) of this section. If you choose to demonstrate compliance using periodic screenings, you must comply with the requirements in paragraphs (b)(1) through (5) of this section and comply with the recordkeeping and reporting requirements in § 60.5424b.

(1) You must use one or more alternative test method(s) approved per paragraph (d) of this section to conduct periodic screenings.

(i) The required frequencies for conducting periodic screenings are listed in tables 1 and 2 to this subpart. You must choose the appropriate frequency for conducting periodic screenings based on the minimum aggregate detection threshold of the method used to conduct the periodic screenings. You must also use tables 1 and 2 to this subpart to determine whether you must conduct an annual fugitive emissions survey using OGI, except as provided in paragraph (b)(1)(ii) of this section.

(ii) For well sites, centralized production facilities, and compressor stations subject to quarterly OGI monitoring surveys in § 60.5397b(g)(1)(iv) and/or (v), prior to March 9, 2026, if you use an alternative test method approved per paragraph (d) of this section with a minimum aggregated detection threshold less than or equal to 3 kg/hr, in lieu of conducting periodic screening events at the frequency specified in paragraph (b)(1)(i) of this section, you may conduct periodic screening events quarterly. After March 9, 2026, you must conduct periodic screening events at the frequency specified in paragraph (b)(1)(i) of this section.

(iii) Use of table 1 or 2 to this subpart is based on the required frequency for conducting monitoring surveys in § 60.5397b(g)(1)(i) through (v).

(iv) You may replace one or more individual periodic screening events required by table 1 or 2 to this subpart with an OGI survey. The OGI survey must be conducted according to the requirements outlined in § 60.5397b.

(v) If you use multiple methods to conduct periodic screenings, you must conduct all periodic screenings, regardless of the method used for the individual periodic screening event, at the frequency required for the alternative test method with the highest aggregate detection threshold (*e.g.*, if you use methods with aggregate detection thresholds of 15 kg/hr, your periodic screenings must be conducted monthly). You must also conduct an annual OGI survey if an annual OGI survey is required for the alternative test method with the highest aggregate detection threshold.

(2) You must develop a monitoring plan that covers the collection of fugitive emissions components, covers, and closed vent systems at each site where you will use periodic screenings to demonstrate compliance. You may develop a site-specific monitoring plan, or you may include multiple sites that you own or operate in one plan. At a minimum, the monitoring plan must contain the information specified in paragraphs (b)(2)(i) through (ix) of this section.

- (i) Identification of each site that will be monitored through periodic screening, including latitude and longitude coordinates of the site in decimal degrees to an accuracy and precision of at least four decimals of a degree using the North American Datum of 1983.
 - (ii) Identification of the alternative test method(s) approved per paragraph (d) of this section that will be used for periodic screenings and the spatial resolution (*i.e.*, component-level, area-level, or facility-level) of the technology used for each method.
 - (iii) Identification of and contact information for the entities that will be performing the periodic screenings.
 - (iv) Required frequency for conducting periodic screenings, based on the criteria outlined in paragraph (b)(1) of this section.
 - (v) If you are required to conduct an annual OGI survey by paragraph (b)(1)(i) or (iii) of this section or you choose to replace any individual screening event with an OGI survey, your monitoring plan must also include the information required by § 60.5397b(b).
 - (vi) Procedures for conducting monitoring surveys required by paragraphs (b)(5)(ii)(A), (b)(5)(iii)(A), and (b)(5)(iv)(A) of this section. At a minimum, your monitoring plan must include the information required by § 60.5397b(c)(2), (3), (7), and (8), and (d), as applicable. The provisions of § 60.5397b(d)(3) do not apply for purposes of conducting monitoring surveys required by paragraphs (b)(5)(ii) through (iv) of this section.
 - (vii) Procedures and timeframes for identifying and repairing fugitive emissions components, covers, and closed vent systems from which emissions are detected.
 - (viii) Procedures and timeframes for verifying repairs for fugitive emissions components, covers, and closed vent systems.
 - (ix) Records that will be kept and the length of time records will be kept.
- (3) You must conduct the initial screening of your site according to the timeframes specified in (b)(3)(i) through (v) of this section.
- (i) Within 90 days of the startup of production for each fugitive emissions components affected facility and storage vessel affected facility located at a new well site or centralized production facility.
 - (ii) Within 90 days of the startup of a new compressor station for each fugitive emissions components affected facility and storage vessel affected facility located at a new compressor station.
 - (iii) Within 90 days of the startup of production after modification for each modified fugitive emissions components affected facility and storage vessel affected facility at a well site or centralized production facility.
 - (iv) Within 90 days of modification for each modified fugitive emissions components affected facility and storage vessel affected facility at a compressor station.
 - (v) No later than the final date by which the next monitoring survey required by § 60.5397b(g)(1)(i) through (v) would have been required to be conducted if you were previously complying with the requirements in § 60.5397b and § 60.5416b(a)(1)(ii) and (iii), (2)(ii) through (iv), and (3)(iii) and (iv).
- (4) If you are required to conduct an annual OGI survey by paragraph (b)(1)(i) or (iii) of this section, you must conduct OGI surveys according to the schedule in paragraphs (b)(4)(i) through (iv) of this section.
- (i) You must conduct the initial OGI survey no later than 12 calendar months after conducting the initial screening event in paragraph (b)(3) of this section.

(ii) Each subsequent OGI survey must be conducted no later than 12 calendar months after the previous OGI survey was conducted. Each identified source of fugitive emissions during the OGI survey shall be repaired in accordance with § 60.5397b(h).

(iii) If you replace a periodic screening event with an OGI survey or you are required to conduct a monitoring survey in accordance with paragraph (b)(5)(ii)(A) of this section prior to the date that your next OGI survey under paragraph (b)(4)(ii) of this section is due, the OGI survey conducted in lieu of the periodic screening event or the monitoring survey under paragraph (b)(5)(ii)(A) of this section can be used to fulfill the requirements of paragraph (b)(4)(ii) of this section. The next OGI survey is required to be conducted no later than 12 calendar months after the date of the survey conducted under paragraph (b)(1)(iv) or (b)(5)(ii)(A) of this section.

(iv) You cannot use a monitoring survey conducted under paragraph (b)(5)(iii)(A) or (b)(5)(iv)(A) of this section to fulfill the requirements of paragraph (b)(4)(ii) of this section unless the monitoring survey included all fugitive emission components at the site.

(5) You must investigate confirmed detections of emissions from periodic screening events and repair each identified source of emissions in accordance with paragraphs (b)(5)(i) through (vii) of this section.

(i) You must receive the results of the periodic screening no later than 5 calendar days after the screening event occurs.

(ii) If you use an alternative test method with a facility-level spatial resolution to conduct a periodic screening event and the results of the periodic screening event indicate a confirmed detection of emissions from an affected facility, you must take the actions listed in paragraphs (b)(5)(ii)(A) through (C) of this section.

(A) You must conduct a monitoring survey of all the fugitive emissions components in an affected facility using either OGI or EPA Method 21 to appendix A-7 of this part. You must follow the procedures in your monitoring plan when conducting the survey.

(B) You must inspect all covers and closed vent system(s) with OGI or Method 21 to appendix A-7 to this part in accordance with the requirements in § 60.5416b(b)(1) through (4), as applicable.

(C) You must conduct a visual inspection of all covers and closed vent systems to identify if there are any defects, as defined in § 60.5416b(a)(1)(ii), (a)(2)(iii), or (a)(3)(i), as applicable.

(iii) If you use an alternative test method with an area-level spatial resolution to conduct a periodic screening event and the results of the periodic screening event indicate a confirmed detection of emissions from an affected facility, you must take the actions listed in paragraphs (b)(5)(iii)(A) and (B) of this section, as applicable.

(A) You must conduct a monitoring survey of all your fugitive emissions components located within a 4-meter radius of the location of the periodic screening's confirmed detection using either OGI or EPA Method 21 to appendix A-7 of this part. You must follow the procedures in your monitoring plan when conducting the survey.

(B) If the confirmed detection occurred in the portion of a site that contains a storage vessel or a closed vent system, you must inspect all covers and all closed vent systems that are connected to all storage vessels and closed vent systems that are within a 2-meter radius of the location of the periodic screening's confirmed detection (*i.e.*, you must inspect the whole system that is connected to the portion of the system in the radius of the detected event, not just the portion of the system that falls within the radius of the detected event).

(1) You must inspect the cover(s) and closed vent system(s) with OGI or Method 21 to appendix A-7 to this part in accordance with the requirements in § 60.5416b(b)(1) through (4), as applicable.

(2) You must conduct a visual inspection of the closed vent system(s) and cover(s) to identify if there are any defects, as defined in § 60.5416b(a)(1)(ii), (a)(2)(iii), or (a)(3)(i), as applicable.

(iv) If you use an alternative test method with a component-level spatial resolution to conduct a periodic screening event and the results of the periodic screening event indicate a confirmed detection of emissions from an affected facility, you must take the actions listed in paragraphs (b)(5)(iv)(A) and (B) of this section, as applicable.

(A) You must conduct a monitoring survey of all the fugitive emissions components located within a 1-meter radius of the location of the periodic screening's confirmed detection using either OGI or EPA Method 21 to appendix A-7 of this part. You must follow the procedures in your monitoring plan when conducting the survey.

(B) If the confirmed detection occurred in the portion of a site that contains a storage vessel or a closed vent system, you must inspect all covers and all closed vent systems that are connected to all storage vessels and closed vent systems that are within a 0.5-meter radius of the location of the periodic screening's confirmed detection (*i.e.*, you must inspect the whole system that is connected to the portion of the system in the radius of the detected event, not just the portion of the system that falls within the radius of the detected event).

(1) You must inspect the cover(s) and closed vent system(s) with OGI or Method 21 to appendix A-7 to this part in accordance with the requirements in § 60.5416b(b)(1) through (4), as applicable.

(2) You must conduct a visual inspection of the closed vent system(s) and cover(s) to identify if there are any defects, as defined in § 60.5416b(a)(1)(ii), (a)(2)(iii), or (a)(3)(i), as applicable.

(v) You must repair all sources of fugitive emissions in accordance with § 60.5397b(h) and all emissions or defects of covers and closed vent systems in accordance with § 60.5416b(b)(5), except as specified in this paragraph (b)(5)(v). Except as allowed by § 60.5397b(h)(3) and § 60.5416b(b)(6), all repairs must be completed, including the resurvey verifying the repair, within 30 days of receiving the results of the periodic screening in paragraph (b)(5)(i) of this section.

(vi) If the results of the periodic screening event in paragraph (b)(5)(i) of this section indicate a confirmed detection at an affected facility, and the ground-based monitoring survey and inspections required by paragraphs (b)(5)(ii) through (iv) of this section demonstrate the confirmed detection was caused by a failure of a control device used to demonstrate continuous compliance under this subpart, you must initiate an investigative analysis to determine the underlying primary and other contributing cause(s) of such failure within 24 hours of receiving the results of the monitoring survey and/or inspection. As part of the investigation, you must determine if the control device is operating in compliance with the applicable requirements of § 60.5415b and § 60.5417b, and if not, what actions are necessary to bring the control device into compliance with those requirements as soon as possible and prevent future failures of the control device from the same underlying cause(s).

(vii) If the results of the inspections required in paragraphs (b)(5)(ii) through (iv) of this section indicate that there is an emission or defect in your cover or closed vent system, you must perform an investigative analysis to determine the underlying primary and other contributing cause(s) of emissions from your cover or closed vent system within 5 days of completing the inspection required by paragraphs (b)(5)(ii) through (iv) of this section. The investigative analysis must include a determination

as to whether the system was operated outside of the engineering design analysis and whether updates are necessary for the cover or closed vent system to prevent future emissions from the cover and closed vent system.

(6) You must maintain records as specified in § 60.5420b(c)(4) through (7), (14), and (15), and § 60.5424b(c).

(7) You must submit reports as specified in § 60.5424b.

(c) *Continuous monitoring.* You may choose to demonstrate compliance for your fugitive emissions components affected facility and compliance with continuous inspection and monitoring requirements for your covers and closed vent systems through continuous monitoring using a technology approved in accordance with paragraph (d) of this section. If you choose to demonstrate compliance using continuous monitoring, you must comply and develop a monitoring plan consistent with the requirements in paragraphs (c)(1) through (9) of this section and comply with the recordkeeping and reporting requirements in § 60.5424b.

(1) For the purpose of this section, continuous monitoring means the ability of a methane monitoring system to determine and record a valid methane mass emissions rate or equivalent of affected facilities at least once for every 12-hour block.

(i) The detection threshold of the system must be such that it can detect at least 0.40 kg/hr (0.88 lb/hr) of methane.

(ii) The health of the devices used within the continuous monitoring system must be confirmed for power and function at least twice every six-hour block.

(iii) The continuous monitoring system must transmit all applicable valid data at least once every 24-hours. The continuous monitoring system must transmit all valid data collected, including health checks required in paragraph (c)(1)(ii) of this section.

(iv) The continuous monitoring system must continuously collect data as specified in paragraph (c)(1) of this section, except as specified in paragraphs (c)(1)(iv)(A) through (D) of this section:

(A) The rolling 12-month average operational downtime of the continuous monitoring system must be less than or equal to 10 percent.

(B) Operational downtime of the continuous monitoring system is defined as a period of time for which any monitor fails to collect or transmit data as specified in paragraph (c)(1) of this section or any monitor is out-of-control as specified in paragraph (c)(1)(iv)(C) of this section.

(C) A monitor is out-of-control if it fails ongoing quality assurance checks, as specified in the alternative test method approved under paragraph (d) of this section, or if the monitor output is outside of range. The beginning of the out-of-control period is defined as the time of the failure of the quality assurance check. The end of the out-of-control period is defined as the time when either the monitor passes a subsequent quality assurance check, or a new monitor is installed. The out-of-control period for a monitor outside of range starts at the time when the monitor first reads outside of range and ends when the monitor reads within range again.

(D) The downtime for the continuous monitoring system must be calculated each calendar month. Once 12 months of data are available, at the end of each calendar month, you must calculate the 12-month average by averaging that month with the previous 11 calendar months. You must determine the rolling 12-month average by recalculating the 12-month average at the end of each month.

(2) You must develop a monitoring plan that covers the collection of fugitive emissions components, covers, and closed vent systems for each site where continuous monitoring will be used to demonstrate compliance. At a

minimum, the monitoring plan must contain the information specified in paragraphs (c)(2)(i) through (xii) of this section.

- (i) Identification of each site to be monitored through continuous monitoring, including latitude and longitude coordinates of the site in decimal degrees to an accuracy and precision of at least four decimals of a degree using the North American Datum of 1983.
- (ii) Identification of the alternative test method(s) approved under paragraph (d) of this section used for the continuous monitoring, including the detection principle; the manufacturer, make, and model; instrument manual, if applicable; and the manufacturer's recommended maintenance schedule.
- (iii) If the continuous monitoring system is administered through a third-party provider, contact information where the provider can be reached 24 hours a day.
- (iv) Number and location of monitors. If the continuous monitoring system uses open path technology, you must identify the location of any reflectors used. These locations should be identified by latitude and longitude coordinates in decimal degrees to an accuracy and precision of at least five decimals of a degree using the North American Datum of 1983.
- (v) Discussion of system calibration requirements, including but not limited to, the calibration procedures and calibration schedule for the detection systems and meteorology systems.
- (vi) Identification of critical components and infrastructure (*e.g.*, power, data systems) and procedures for their repairs.
- (vii) Procedures for out-of-control periods.
- (viii) Procedures for establishing baseline emissions, including the identification of any sources with methane emissions not subject to this subpart. The procedures for establishing the baseline emissions must account for variability in the operation of the site. Operation of the site during the development of the baseline emissions must represent the site's expected annual production or throughput.
- (ix) Procedures for determining when a fugitive emissions event is detected by the continuous monitoring technology.
- (x) Procedures and timeframes for identifying and repairing fugitive emissions components, covers, and closed vent systems from which emissions are detected.
- (xi) Procedures and timeframes for verifying repairs for fugitive emissions components, covers, and closed vent systems.
- (xii) Records that will be kept and the length of time records will be kept.

(3) You must install and begin conducting monitoring with your continuous monitoring system according to the timeframes specified in paragraphs (c)(3)(i) through (v) of this section.

- (i) Within 120 days of the startup of production for each fugitive emissions components affected facility and storage vessel affected facility located at a new well site or centralized production facility.
- (ii) Within 120 days of the startup of a new compressor station for each fugitive emissions components affected facility and storage vessel affected facility located at a new compressor station.
- (iii) Within 120 days of the startup of production after modification for each modified fugitive emissions components affected facility and storage vessel affected facility at a well site or centralized production facility.

- (iv) Within 120 days of modification for each modified fugitive emissions components affected facility and storage vessel affected facility at a compressor station.
 - (v) No later than the final date by which the next monitoring survey required by § 60.5397b(g)(1)(i) through (v) would have been required to be conducted if you were previously complying with the requirements in § 60.5397b and § 60.5416b(a)(1)(ii) and (iii), (2)(ii) through (iv), and (3)(iii) and (iv).
- (4) You are subject to the following action-levels as specified in paragraphs (c)(4)(i) and (ii) of this section for any affected facilities located at a well site, centralized production facility, or compressor station.
- (i) For affected facilities located at a wellhead only well site, the action levels are as follows:
 - (A) The 90-day rolling average action-level is 1.2 kg/hr (2.6 lb/hr) of methane over the site-specific baseline emissions.
 - (B) The 7-day rolling average action level is 15 kg/hr (34 lb/hr) of methane over site-specific baseline emissions.
 - (ii) For affected facilities located at well sites with major production and processing equipment (including small well sites), centralized production facilities, and compressor stations, the action levels are as follows:
 - (A) The 90-day rolling average action-level is 1.6 kg/hr (3.6 lb/hr) of methane over the site-specific baseline emissions.
 - (B) The 7-day rolling average action level is 21 kg/hr (46 lb/hr) of methane over the site-specific baseline emissions.
- (5) You must establish site-specific baseline emissions upon initial installation and activation of a continuous monitoring system. You must establish the baseline emissions under the conditions outlined in paragraphs (c)(5)(i) through (iii) of this section. You must determine the baseline emission rates according to paragraphs (c)(5)(iv) and (v) of this section. The baseline must be established initially and any time there is a major change to the processing equipment at a well site (including small well sites), centralized production facility, or compressor station.
- (i) Inspect all fugitive emissions components according to the requirements in § 60.5397b and covers and closed vent systems according to the requirements in § 60.5416b. This includes all fugitive emissions components, covers, and closed vent systems, regardless of whether they are regulated by this subpart. Repairs of any fugitive emissions, leaks, or defects found during the inspection must be completed prior to beginning the period in paragraph (c)(5)(iii) of this section.
 - (ii) Verify control devices (*e.g.*, flares) on all affected sources are operating in compliance with the applicable requirements of § 60.5415b and § 60.5417b. You must ensure that all control devices are operating in compliance with the applicable regulations prior to beginning the period in paragraph (b)(5)(iii) of this section. Verify that all other methane emission sources (*e.g.*, reciprocating engines) located at the site are operating consistent with any applicable regulations. You must ensure that these sources are operating in compliance with the applicable regulations prior to beginning the period in paragraph (b)(5)(iii) of this section.
 - (iii) Using the alternative test method approved under paragraph (d) of this section, record the site-level emission rate from your continuous monitoring system for 30 operating days. You must minimize any activities that are not normal, day-to-day activities during this 30 operating day period. Document any maintenance activities and the period (including the start date and time and end date and time) such activities occurred during the 30 operating day period.

- (iv) Determine the site-specific baseline by calculating the mean emission rate (kg/hr of methane) for the 30 operating day period, less any time periods when maintenance activities were conducted.
 - (v) The site-specific baseline emission rate must be no more than 10 times the applicable 90-day action-level defined in paragraphs (c)(4)(i) and (ii) of this section.
- (6) Calculate the emission rate from your site according to paragraphs (c)(6)(i) through (iii) of this section. Compare the emission rate calculated in this paragraph (c)(6) to the appropriate action levels in paragraph (c)(4) of this section to determine whether you have exceeded an action level.
- (i) Each calendar day, calculate the daily average mass emission rate in kg/hr of methane from your continuous monitoring system.
 - (ii) Once the system has been operating for 7 calendar days, at the end of each calendar day calculate the 7-day average mass emission rate by averaging the mass emission rate from that day with the mass emission rate from the previous 6 calendar days. Subtract the site-specific baseline mass emission rate from the 7-day average mass emission rate when comparing the mass emission rate to the applicable action level. Determine the 7-day rolling average by recalculating the 7-day average each calendar day, less the site-specific baseline.
 - (iii) Once the system has been operating for 90 calendar days, at the end of each calendar day calculate the 90-day average mass emission rate by averaging the mass emission rate from that day with the mass emission rate from the previous 89 calendar days. Subtract the site-specific baseline emission rate from the 90-day average mass emission rate when comparing the mass emission rate to the applicable action level. Determine the 90-day rolling average by recalculating the 90-day average each calendar day, less the site-specific baseline.
- (7) Within 5 days of determining that either of your action levels in paragraph (c)(4) of this section has been exceeded, you must initiate an investigative analysis to determine the underlying primary and contributing cause(s) of such exceedance and actions to be taken to reduce the mass emission rate below the applicable action level.
- (i) You must complete the investigative analysis and take initial steps to bring the mass emission rate below the action level no later than 5 days after determining there is an exceedance of the action level in paragraph (c)(4)(i)(B) or (c)(4)(ii)(B) of this section.
 - (ii) You must complete the investigative analysis and take initial steps to bring the mass emission rate below the action level no later than 30 days after determining there is an exceedance of the action level in paragraph (c)(4)(i)(A) or (c)(4)(ii)(A) of this section.
- (8) You must develop a mass emission rate reduction plan if you meet any of the criteria in paragraphs (c)(8)(i) through (iii) of this section. The plan must describe the action(s) completed to date to reduce the mass emission rate below the action level, additional measures that you propose to employ to reduce methane emissions below the action level, and a schedule for completion of these measures. You must submit the plan to the Administrator within 60 days of initially determining there is an exceedance of an action level in paragraph (c)(4) of this section.
- (i) If, upon completion of the initial actions required under paragraph (c)(7) of this section, the average mass emission rate for the following 30-day period is not below the applicable action level in paragraph (c)(4)(i)(A) or (c)(4)(ii)(A) of this section. The beginning of the 30-day period starts on the calendar day following completion of the initial actions in paragraph (c)(7) of this section.
 - (ii) If, upon completion of the initial actions required under paragraph (c)(6) of this section, the average mass emission rate for the following 24-hour period is not below the applicable action level in paragraph

(c)(4)(i)(B) or (c)(4)(ii)(B) of this section. The average mass emission rate will be the mass emission rate calculated according to paragraph (c)(6)(i) of this section for the calendar day following completion of the initial corrective actions in paragraph (c)(7) of this section.

(iii) All actions needed to reduce the average mass emission rate below the action level require more than 30 days to implement.

(9) You must maintain the records as specified in § 60.5420b(c)(4) through (c)(7), (c)(14) and (c)(15), and § 60.5424b(e). You must submit the reports as specified in § 60.5420b(b)(1), and (b)(4) through (10) and § 60.5424b.

(d) *Alternative Test Method for Methane Detection Technology.* Any alternative test method for methane detection technology used to meet the requirements specified in paragraphs (b) or (c) of this section or § 60.5371b must be approved by the Administrator as specified in this paragraph (d). Approval of an alternative test method for methane detection technology will include consideration of the combination of the measurement technology and the standard protocol for its operation. Any entity meeting the requirements in paragraph (d)(2) of this section may submit a request for an alternative test method for methane detection technology. At a minimum, the request must follow the requirements outlined in paragraph (d)(3) of this section. Approved alternative test methods for methane detection technology that are broadly applicable will be posted on the EPA's Emission Measurement Center web page (<https://www.epa.gov/emc/oil-and-gas-alternative-test-methods>). Any owner or operator that meets the specific applicability for the alternative test method, as outlined in the alternative test method for methane detection technology, may use the alternative test method to comply with the requirements of paragraph (b) or (c) of this section, as applicable, in lieu of the requirements for fugitive emissions components affected facilities in § 60.5397b and covers and closed vent systems in § 60.5416b(a)(1)(ii) and (iii), (a)(2)(ii) through (iv), and (a)(3)(iii) and (iv). Certified third-party notifiers may use the alternative test method to identify super-emitter events in § 60.5371b(b)(1)(ii).

(1) A request for an alternative test method for methane detection technology, along with the required supporting information, must be submitted to the EPA through the alternative methane detection technology portal at <https://www.epa.gov/emc/oil-and-gas-alternative-test-methods>. The EPA may make all the information submitted through the portal available to the public without further notice to you. Do not use the portal to submit information you claim as confidential business information (CBI). If you wish to assert a CBI claim for some of the information in your submittal, submit the portion of the information claimed as CBI to the OAQPS CBI office. Clearly mark the information that you claim to be CBI. Information not marked as CBI may be authorized for public release without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. All CBI claims must be asserted at the time of submission. Anything submitted using the portal cannot later be claimed CBI. The preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol, or other online file sharing services. Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address oaqpscbi@epa.gov and should include clear CBI markings and be flagged to the attention of the Leader, Measurement Technology Group. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if you do not have your own file sharing service, please email oaqpscbi@epa.gov to request a file transfer link. If you cannot transmit the file electronically, you may send CBI information through the postal service to the following address: U.S. EPA, Attn: OAQPS Document Control Officer and Measurement Technology Group Leader, Mail Drop: C404-02, 109 T.W. Alexander Drive, P.O. Box 12055, RTP, North Carolina 27711. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

(i) The Administrator will complete an initial review for completeness within 90 days of receipt and notify the submitter of the results of the review.

(ii) If the entity submitting the request does not meet the requirements in paragraph (d)(2) of this section or the request does not contain the information in paragraph (d)(3) of this section, the submitter will be notified. The submitter may choose to revise the information and submit a new request for an alternative test method.

(iii) Within 270 days of receipt of an alternative test method request that was determined to be complete, the Administrator will determine whether the requested alternative test method is adequate for indicating compliance with the requirements for monitoring fugitive emissions components affected facilities in § 60.5397b and continuous inspection and monitoring of covers and closed vent systems in § 60.5416b and/or for identifying super-emitter events in § 60.5371b, except that the Administrator is not required to make determinations on such requests for methods for identifying super emitter events in § 60.5371b before January 22, 2027. The Administrator will issue either an approval or disapproval in writing to the submitter. Approvals may be considered site-specific or more broadly applicable. Broadly applicable alternative test methods and approval letters will be posted at <https://www.epa.gov/emc/oilandgasapproved-alternative-test-methods-approvals>. If the Administrator fails to provide the submitter a decision on approval or disapproval within 270 days, the alternative test method will be given conditional approval status and posted on this same web page, except that conditional approval will not be given for purposes of identifying super-emitter events in § 60.5371b before January 22, 2027. If the Administrator finds any deficiencies in the request and disapproves the request in writing, the owner or operator may choose to revise the information and submit a new request for an alternative test (iv) If the Administrator finds reasonable grounds to dispute the results obtained by any alternative test method for the purposes of demonstrating compliance with a relevant standard, the Administrator may require you to demonstrate compliance according to § 60.5397b for fugitive emissions components affected facilities and § 60.5416b for covers and closed vent systems.

(2) Any entity may submit an alternative test method for consideration, so long as you meet the requirements in paragraphs (d)(2)(i) through (iv) of this section.

(i) An entity is limited to any individual or organization located in or that has representation in the United States.

(ii) If an entity is not considered an owner or operator of an affected facility regulated under this subpart or subpart OOOOa of this part or is not the owner or operator of a designated facility regulated under subpart OOOOc of this part, the provisions of paragraphs (d)(2)(ii)(A) and (B) of this section apply.

(A) The entity must directly represent the provider of the measurement system using advanced methane detection technology.

(B) The measurement system must have been applied to methane measurements or monitoring in the oil and gas sector either domestically or internationally.

(iii) The underlying technology or technologies must be readily available for use, meaning that the measurement system using these technologies has either been:

(A) Sold, leased, or licensed, or offered for sale, lease, or license to the general public or;

(B) Developed by an owner or operator for internal use and/or use by external partners.

(iv) The entity must be able to provide and submit to the Administrator the information required in paragraph (d)(3) of this section.

(3) The request must contain the information specified in paragraphs (d)(3)(i) through (vii) of this section.

(i) The submitter's name, mailing address, phone number and email address.

(ii) The desired applicability of the technology (*i.e.*, site-specific, basin-specific, or broadly applicable across the sector, super-emitter detection).

(iii) Description of the measurement technology, including the physical components, the scientific theory, and the known limitations. At a minimum, this description must contain the information in paragraphs (d)(3)(iii)(A) through (D) of this section.

(A) Description of scientific theory and appropriate references outlining the underlying technology (*e.g.*, reference material, literature review).

(B) Description of the physical instrumentation.

(C) Type of measurement and application (*e.g.*, remote or in-situ measurements, mobile, airborne).

(D) Known limitation of the technology, including application limitations and weather limitations.

(iv) Description of how the measurement technology is converted to a methane mass emission rate (*i.e.*, kg/hr of methane) or equivalent. At a minimum this description must contain the information in paragraphs (d)(3)(iv)(A) through (F) of this section.

(A) Detailed workflow and description covering all steps and processes from measurement technology signal output to final, validated mass emission rate or equivalent. These workflows must cover the material in paragraph (d)(3)(v) of this section and put all technical components into context. The workflow must also cover the technology from data collection to generation of the final product and identify any raw data processing procedures; identification of whether processing steps are manual or automated, and when and what quality assurance checks are made to the data, including raw data, processed data, and output data.

(B) Description of how any meteorological data used are collected or sourced, including a description how the data are used.

(C) Description of any model(s) (*e.g.*, AERMOD) used, including how inputs are determined or derived.

(D) All calculations used, including the defined variables for any of these calculations and a description of their purposes.

(E) Descriptions of a-priori methods and datasets used, including source and version numbers when applicable.

(F) Description of algorithms/machine learning procedures used in the data processing, if applicable.

(v) Description of how all data collected and generated by the measurement system are handled and stored. At a minimum this description must contain the information in paragraphs (d)(3)(v)(A) through (C) of this section.

(A) How the data, including metadata, are collected, maintained, and stored.

(B) A description of how raw data streams are processed and manipulated, including how the resultant data processing is documented and how version controlled is maintained.

(C) A description of what data streams are provided to the end-user of the data and how the data are delivered to the end-user.

(vi) Supporting information verifying that the technology meets the aggregate detection threshold(s) defined in paragraphs (b) and/or (c) of this section or in § 60.5371b, including supporting data to demonstrate the aggregate detection threshold of the measurement technology as applied in the field and if applicable, how probability of detection is determined. For the purpose of this subpart the average aggregate detection threshold is the average of all site-level detection thresholds from a single deployment (*e.g.*, a singular flight that surveys multiple well sites, centralized production facility, and/or compressor stations) of a technology, unless this technology is to be applied to § 60.5371b. When the technology is applied to § 60.5371b, then the aggregate detection threshold is the average of all site-level detection thresholds from a single deployment in the same basin and field. At a minimum, you must provide the information identified in paragraphs (d)(3)(vi)(A) through (D) of this section.

(A) Published reports (*e.g.*, scientific papers) produced by either the submitting entity or an outside entity evaluating the submitted measurement technology that has been independently evaluated. The published reports must identify either a site-level or aggregate detection threshold and be accompanied with sufficient supporting data to evaluate whether the performance metrics of the alternative testing procedures in paragraph (d)(3)(vi)(C) of this section are adequate and the data was collected consistent with those alternative testing procedures. The supporting data may be included in the published report or may be submitted separately.

(B) Standard operating procedures including safety considerations, measurement limitations, personnel qualification/responsibilities, equipment and supplies, data and record management, and quality assurance/quality control (*i.e.*, initial and ongoing calibration procedures, data quality indicators, and data quality objectives).

(C) Detailed description of the alternative testing procedure(s), preferably in the format described in Guideline Document 45 on the Emission Measurement Center's website (available at <https://www.epa.gov/sites/default/files/2020-08/documents/gd-045.pdf>). The detailed description must address all key elements of the requested method(s) and must include objectives to ensure the detection threshold(s) required in paragraph (d)(3)(vi) of this section are maintained, including procedures for verifying the detection threshold and/or or probability of detection is maintained under field conditions.

(D) Any documents provided to end-users of the data generated by the measurement system, including but not limited to client products, manuals, and frequently asked questions documents.

(vii) If the technology will be used to monitor the collection of fugitive emissions components, covers, and closed vent systems at a well site, centralized production facility, or compressor station, you must submit supporting information verifying the spatial resolution of technology, as defined in paragraphs (d)(3)(vii)(A) through (C) of this section. This supporting information must be in the form of a published reports (*e.g.*, scientific papers) produced by either the submitting entity or an outside entity evaluating the submitted measurement technology that has been independently evaluated. The report must include sufficient supporting data to evaluate whether the performance metrics of the alternative testing procedures in paragraph (d)(3)(vi)(C) of this section are adequate and the data was collected consistent with those alternative testing procedures.

(A) Facility-level spatial resolution means a technology with the ability to identify emissions within the boundary of a well site, centralized production facility, or compressor station.

(B) Area-level spatial resolution means a technology with the ability to identify emissions within a radius of 2 meters of the emission source.

(C) Component-level spatial resolution means a technology with the ability to identify emissions within a radius of 0.5 meter of the emission source.

§ 60.5399b What are the alternative means of emission limitations for GHG and VOC emissions from well completions, liquids unloading operations, centrifugal compressors, reciprocating compressors, fugitive emissions components, and process unit equipment affected facilities; and what are the alternative fugitive emissions standards based on State, local, and Tribal programs?

This section provides procedures for the submittal and approval of alternative means of emission limitation for GHG and VOC based on work practices for well completions, liquids unloading operations, centrifugal compressors, reciprocating compressors, fugitive emissions components and process unit equipment affected facilities. This section also provides procedures for the submittal and approval of alternative fugitive emissions standards based on programs under state, local, or Tribal authorities for the fugitive emissions components affected facility. Paragraphs (a) through (d) of this section outline the procedure for submittal and approval of alternative means of emission limitation for methane and VOC. Paragraphs (e) through (i) of this section outline the procedure for submittal and approval of alternative fugitive emissions standards. The requirements for a monitoring plan specified in § 60.5397b(c) and (d) apply to the alternative fugitive emissions standards in this section.

(a) *Alternative means of emission limitation.* If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in methane and VOC emissions at least equivalent to the reduction in methane and VOC emissions achieved under § 60.5375b, § 60.5376b, § 60.5380b, § 60.5385b, § 60.5397b, § 60.5400b, or § 60.5401b, the Administrator will publish, in the Federal Register, a notice permitting the use of that alternative means for the purpose of compliance with § 60.5375b, § 60.5376b, § 60.5380b, § 60.5385b, § 60.5397b, § 60.5400b, or § 60.5401b. The authority to approve an alternative means of emission limitation is retained by the Administrator and shall not be delegated to States under section 111(c) of the CAA.

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

(c) *Evaluation guidelines.* Determination of equivalence to the design, equipment, work practice, or operational requirements of this section will be evaluated by the following guidelines:

(1) The applicant must provide information that is sufficient for demonstrating the alternative means of emission limitation achieves emission reductions that are at least equivalent to the emission reductions that would be achieved by complying with the relevant standards. At a minimum, the application must include the following information:

(i) Details of the specific equipment or components that would be included in the alternative.

(ii) A description of the alternative work practice, including, as appropriate, the monitoring method, monitoring instrument or measurement technology, and the data quality indicators for precision and bias.

(iii) The method detection limit of the technology, technique, or process and a description of the procedures used to determine the method detection limit. At a minimum, the applicant must collect, verify, and submit field data encompassing seasonal variations to support the determination of the method detection limit. The field data may be supplemented with modeling analyses, controlled test site data, or other documentation.

(iv) Any initial and ongoing quality assurance/quality control measures necessary for maintaining the technology, technique, or process, and the timeframes for conducting such measures.

(v) Frequency of measurements. For continuous monitoring techniques, the minimum data availability.

(vi) Any restrictions for using the technology, technique, or process.

(vii) Initial and continuous compliance procedures, including recordkeeping and reporting, if the compliance procedures are different than those specified in this subpart.

(2) For each technology, technique, or process for which a determination of equivalency is requested, the application must provide a demonstration that the emission reduction achieved by the alternative means of emission limitation is at least equivalent to the emission reduction that would be achieved by complying with the relevant standards in this subpart.

(d) *Approval of alternative means of emission limitation.* Any alternative means of emission limitations approved under this section shall constitute a required work practice, equipment, design, or operational standard within the meaning of section 111(h)(1) of the CAA.

(e) *Alternative fugitive emissions standards.* If, in the Administrator's judgment, an alternative fugitive emissions standard will achieve a reduction in methane and VOC emissions at least equivalent to the reductions achieved under § 60.5397b, the Administrator will publish, in the Federal Register, a notice permitting use of the alternative fugitive emissions standard for the purpose of compliance with § 60.5397b. The authority to approve alternative fugitive emissions standards is retained by the Administrator and shall not be delegated to States under section 111(c) of the CAA.

(f) *Notice.* Any notice under paragraph (e) of this section will be published only after notice and an opportunity for public hearing.

(g) *Evaluation guidelines.* Determination of alternative fugitive emissions standards to the design, equipment, work practice, or operational requirements of § 60.5397b will be evaluated by the following guidelines:

- (1) The monitoring instrument, including the monitoring procedure;
- (2) The monitoring frequency;
- (3) The fugitive emissions definition;
- (4) The repair requirements; and
- (5) The recordkeeping and reporting requirements.

(h) *Approval of alternative fugitive emissions standard.* Any alternative fugitive emissions standard approved under this section shall:

- (1) Constitute a required design, equipment, work practice, or operational standard within the meaning of section 111(h)(1) of the CAA; and
- (2) Be made available for use by any owner or operator in meeting the relevant standards and requirements established for affected facilities under § 60.5397b.

(i) *Notification.*

- (1) An owner or operator must notify the Administrator of adoption of the alternative fugitive emissions standards within the first annual report following implementation of the alternative fugitive emissions standard, as specified in § 60.5420b(a)(3).
- (2) An owner or operator implementing one of the alternative fugitive emissions standards must submit the reports specified in § 60.5420b(b)(9)(iii). An owner or operator must also maintain the records specified by the specific alternative fugitive emissions standard for a period of at least 5 years.

§ 60.5400b What GHG and VOC standards apply to process unit equipment affected facilities?

This section applies to process unit equipment affected facilities located at an onshore natural gas processing plant. You must comply with the requirements of paragraphs (a) through (l) of this section to reduce methane and VOC emissions from equipment leaks, except as provided in § 60.5402b. As an alternative to the standards in this section, you may comply with the requirements in § 60.5401b.

(a) *General standards.* You must comply with the requirements in paragraphs (b) through (d) of this section for each pump in light liquid service, pressure relief device in gas/vapor service, valve in gas/vapor or light liquid service, and connector in gas/vapor or light liquid service, as applicable. You must comply with the requirements in paragraph (e) of this section for each open-ended valve or line. You must comply with the requirements in paragraph (f) of this section for each closed vent system and control device used to comply with equipment leak provisions in this section. You must comply with paragraph (g) of this section for each pump, valve, and connector in heavy liquid service and pressure relief device in light liquid or heavy liquid service. You must make repairs as specified in paragraph (h) of this section. You must demonstrate initial compliance with the standards as specified in paragraph (i) of this section. You must demonstrate continuous compliance with the standards as specified in paragraph (j) of this section. You must perform the reporting as specified in paragraph (k) of this section. You must perform the recordkeeping as required in paragraph (l) of this section.

(1) You may apply to the Administrator for permission to use an alternative means of emission limitation that achieves a reduction in emissions of methane and VOC at least equivalent to that achieved by the controls required in this subpart according to the requirements of § 60.5399b.

(2) Each piece of equipment is presumed to have the potential to emit methane or VOC unless an owner or operator demonstrates that the piece of equipment does not have the potential to emit methane or VOC. For a piece of equipment to be considered not to have the potential to emit methane or VOC, the methane and VOC content of a gaseous stream must be below detection limits using Method 18 of appendix A-6 to this part. Alternatively, if the piece of equipment is in wet gas service, you may choose to determine the methane and VOC content of the stream is below the detection limit of the methods described in ASTM E168-16(R2023), E169-16(R2022), or E260-96 (all incorporated by reference, see § 60.17).

(b) *Monitoring surveys.* You must monitor for leaks using OGI in accordance with appendix K of this part, unless otherwise specified in paragraphs (c) or (d) of this section.

(1) Monitoring surveys must be conducted bimonthly.

(2) Any emissions observed using OGI are defined as a leak.

(c) *Additional requirements for pumps in light liquid service.* In addition to the requirements in paragraph (b), you must conduct weekly visual inspections of all pumps in light liquid service for indications of liquids dripping from the pump seal, except as specified in paragraphs (c)(3) and (4) of this section. If there are indications of liquids dripping from the pump seal, you must follow the procedure specified in either paragraph (c)(1) or (2) of this section.

(1) Monitor the pump within 5 calendar days using OGI in accordance with Appendix K or the methods specified in § 60.5403b. A leak is detected if any emissions are observed using OGI or if an instrument reading of 2,000 ppmv or greater is provided using Method 21 of appendix A-7 to this part.

(2) Designate the visual indications of liquids dripping as a leak and repair the leak as specified in paragraph (h) of this section.

(3) If any pump is equipped with a closed vent system capable of capturing and transporting any leakage from the seal or seals to a process, fuel gas system, or a control device that complies with the requirements of paragraph (f) of this section, it is exempt from the weekly inspection requirements in paragraph (c) of this section.

(4) Any pump that is located within the boundary of an unmanned plant site is exempt from the weekly visual inspection requirements in paragraph (c) of this section, provided that each pump is visually inspected as often as practicable and at least bimonthly.

(d) *Additional requirements for pressure relief devices in gas/vapor service.* In addition to the requirements in paragraph (b) of this section, you must monitor each pressure relief device as specified in paragraph (d)(1) of this section, except as specified in paragraphs (d)(2) and (3) of this section.

(1) You must monitor each pressure relief device within 5 calendar days after each pressure release to detect leaks using the methods specified in § 60.5403b. A leak is detected if any emissions are observed using OGI or if an instrument reading of 500 ppmv or greater is provided using Method 21 of appendix A-7 to this part.

(2) Any pressure relief device that is located in a nonfractionating plant that is monitored only by non-plant personnel may be monitored after a pressure release the next time the monitoring personnel are onsite or within 30 calendar days after a pressure release, whichever is sooner, instead of within 5 calendar days as specified in paragraph (d)(1) of this section. No pressure relief device described in this paragraph may be allowed to operate for more than 30 calendar days after a pressure release without monitoring.

(3) Any pressure relief device that is routed to a process or fuel gas system or equipped with a closed vent system capable of capturing and transporting leakage through the pressure relief device to a control device as described in paragraph (f) of this section is exempt from the requirements of paragraph (d)(1) of this section.

(e) *Open-ended valves or lines.* Each open-ended valve or line must be equipped with a cap, blind flange, plug, or a second valve, except as provided in paragraphs (e)(4) and (5) of this section. The cap, blind flange, plug, or second valve must seal the open end of the valve or line at all times except during operations requiring process fluid flow through the open-ended valve or line.

(1) If evidence of a leak is found at any time by AVO, or any other detection method, a leak is detected.

(2) Each open-ended valve or line equipped with a second valve must be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed.

(3) When a double block-and-bleed system is being used, the bleed valve or line may remain open during operations that require venting the line between the block valves but shall remain closed at all other times.

(4) Open-ended valves or lines in an emergency shutdown system which are designed to open automatically in the event of a process upset are exempt from the requirements of this section.

(5) Open-ended valves or lines containing materials which would autocatalytically polymerize or would present an explosion, serious overpressure, or other safety hazard if capped or equipped with a double block-and-bleed system as specified in paragraphs (e) introductory text, (e)(2), and (3) of this section are exempt from the requirements of this section.

(f) *Closed vent systems and control devices.* Closed vent systems used to comply with the equipment leak provisions of this section must comply with the requirements in §§ 60.5411b and 60.5416b. Control devices used to comply with the equipment leak provisions of this section must comply with the requirements in §§ 60.5412b, 60.5415b(f), and 60.5417b.

(g) *Pumps, valves, and connectors in heavy liquid service and pressure relief devices in light liquid or heavy liquid service.* If evidence of a potential leak is found at any time by AVO, or any other detection method, a leak is detected and must be repaired in accordance with paragraph (h) of this section.

(h) *Repair requirements.* When a leak is detected, you must comply with the requirements of paragraphs (h)(1) through (5) of this section, except as provided in paragraph (h)(6) of this section.

- (1) A weatherproof and readily visible identification tag, marked with the equipment identification number, must be attached to the leaking equipment. The identification tag on equipment may be removed after it has been repaired.
- (2) A first attempt at repair must be made as soon as practicable, but no later than 5 calendar days after the leak is detected. A first attempt at repair is not required if the leak is detected using OGI and the equipment identified as leaking would require elevating the repair personnel more than 2 meters above a support surface.
 - (i) First attempts at repair for pumps in light liquid or heavy liquid service include, but are not limited to, the practices described in paragraphs (h)(2)(i)(A) and (B) of this section, where practicable.
 - (A) Tightening the packing gland nuts.
 - (B) Ensuring that the seal flush is operating at design pressure and temperature.
 - (ii) For each valve where a leak is detected, you must comply with (h)(2)(ii)(A), (B) or (C), and (D) of this section.
 - (A) Repack the existing valve with a low-e packing.
 - (B) Replace the existing valve with a low-e valve; or
 - (C) Perform a drill and tap repair with a low-e injectable packing.
 - (D) An owner or operator is not required to utilize a low-e valve or low-e packing to replace or repack a valve if the owner or operator demonstrates that a low-e valve or low-e packing is not technically feasible. Low-e valve or low-e packing that is not suitable for its intended use is considered to be technically infeasible. Factors that may be considered in determining technical infeasibility include: retrofit requirements for installation (e.g., re-piping or space limitation), commercial unavailability for valve type, or certain instrumentation assemblies.
- (3) Repair of leaking equipment must be completed within 15 calendar days after detection of each leak, except as provided in paragraphs (h)(4), (5) and (6) of this section.
- (4) If the repair for visual indications of liquids dripping for pumps in light liquid service can be made by eliminating visual indications of liquids dripping, you must make the repair within 5 calendar days of detection.
- (5) If the repair for AVO or other indication of a leak for open-ended valves or lines; pumps, valves, or connectors in heavy liquid service; or pressure relief devices in light liquid or heavy liquid service can be made by eliminating the AVO, or other indication of a potential leak, you must make the repair within 5 calendar days of detection.
- (6) Delay of repair of equipment for which leaks have been detected is allowed if repair within 15 days is technically infeasible without a process unit shutdown or as specified in paragraphs (h)(6)(i) through (v) of this section. Repair of this equipment shall occur before the end of the next process unit shutdown. Monitoring to verify repair must occur within 15 days after startup of the process unit.
 - (i) Delay of repair of equipment is allowed for equipment which is isolated from the process, and which does not have the potential to emit methane or VOC.
 - (ii) Delay of repair for valves and connectors is allowed if the conditions in paragraphs (h)(6)(ii)(A) and (B) of this section are met.
 - (A) You must demonstrate that emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay of repair, and

(B) When repair procedures are conducted, the purged material is collected and destroyed or recovered in a control device complying with paragraph (f) of this section.

(iii) Delay of repair for pumps is allowed if the conditions in paragraphs (h)(6)(iii)(A) and (B) of this section are met.

(A) Repair requires the use of a dual mechanical seal system that includes a barrier fluid system, and

(B) Repair is completed as soon as practicable, but not later than 6 months after the leak was detected.

(iv) If delay of repair is required to repack or replace the valve, you may use delay of repair. Delay of repair beyond a process unit shutdown is allowed for a valve, if valve assembly replacement is necessary during the process unit shutdown, valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted. Delay of repair beyond the next process unit shutdown will not be allowed unless the next process unit shutdown occurs sooner than 6 months after the first process unit shutdown.

(v) When delay of repair is allowed for a leaking pump, valve, or connector that remains in service, the pump, valve, or connector may be considered to be repaired and no longer subject to delay of repair requirements if two consecutive bimonthly monitoring results show no leak remains.

(i) *Initial compliance.* You must demonstrate initial compliance with the standards that apply to equipment leaks at onshore natural gas processing plants as required by § 60.5410b(h).

(j) *Continuous compliance.* You must demonstrate continuous compliance with the standards that apply to equipment leaks at onshore natural gas processing plants as required by § 60.5415b(j).

(k) *Reporting.* You must perform the reporting requirements as specified in § 60.5420b(b)(1) and (11) through (13), as applicable, and § 60.5422b.

(l) *Recordkeeping.* You must perform the recordkeeping requirements as specified in § 60.5420b(c)(8) and (10) through (13), as applicable, and § 60.5421b.

§ 60.5401b What are the alternative GHG and VOC standards for process unit equipment affected facilities?

This section provides alternative standards for process unit equipment affected facilities located at an onshore natural gas processing plant. You may choose to comply with the standards in this section instead of the requirements in § 60.5400b. For purposes of the alternative standards provided in this section, you must comply with the requirements of paragraphs (a) through (m) of this section to reduce methane and VOC emissions from equipment leaks, except as provided in § 60.5402b.

(a) *General standards.* You must comply with the requirements in paragraphs (b) of this section for each pump in light liquid service. You must comply with the requirements of paragraph (c) of this section for each pressure relief device in gas/vapor service. You must comply with the requirements in paragraph (d) of this section for each open-ended valve or line. You must comply with the requirements in paragraph (e) of this section for each closed vent system and control device used to comply with equipment leak provisions in this section. You must comply with paragraph (f) of this section for each valve in gas/vapor or light liquid service. You must comply with paragraph (g) of this section for each pump, valve, and connector in heavy liquid service and pressure relief device in light liquid or heavy liquid service. You must comply with paragraph (h) of this section for each connector in gas/vapor and light liquid service. You must make repairs as specified in paragraph (i) of this section. You must demonstrate initial compliance with the standards as specified in paragraph (j) of this section. You must demonstrate continuous compliance with the standards as specified in paragraph (k) of this section. You must perform the reporting

requirements as specified in paragraph (l) of this section. You must perform the recordkeeping requirements as required in paragraph (m) of this section.

(1) You may apply to the Administrator for permission to use an alternative means of emission limitation that achieves a reduction in emissions of methane and VOC at least equivalent to that achieved by the controls required in this subpart according to the requirements of § 60.5399b.

(2) Each piece of equipment is presumed to have the potential to emit methane or VOC unless an owner or operator demonstrates that the piece of equipment does not have the potential to emit methane or VOC. For a piece of equipment to be considered not to have the potential to emit methane or VOC, the methane and VOC content of a gaseous stream must be below detection limits using Method 18 of appendix A-6 to this part. Alternatively, if the piece of equipment is in wet gas service, you may choose to determine the methane and VOC content of the stream is below the detection limit of the methods described in ASTM E168-16(R2023), E169-16(R2022), or E260-96 (all incorporated by reference, see § 60.17).

(b) *Pumps in light liquid service.* You must monitor each pump in light liquid service monthly to detect leaks by the methods specified in § 60.5403b, except as provided in paragraphs (b)(2) through (6) of this section. A leak is defined as an instrument reading of 2,000 ppmv or greater. A pump that begins operation in light liquid service after the initial startup date for the process unit must be monitored for the first time within 30 days after the end of its startup period, except for a pump that replaces a leaking pump and except as provided in paragraphs (b)(2) through (6) of this section.

(1) In addition to the requirements in paragraph (b) of this section, you must conduct weekly visual inspections of all pumps in light liquid service for indications of liquids dripping from the pump seal. If there are indications of liquids dripping from the pump seal, you must follow the procedure specified in either paragraph (b)(1)(i) or (ii) of this section.

(i) Monitor the pump within 5 days using the methods specified in § 60.5403b. A leak is defined as an instrument reading of 2,000 ppmv or greater.

(ii) Designate the visual indications of liquids dripping as a leak, and repair the leak as specified in paragraph (i) of this section.

(2) Each pump equipped with a dual mechanical seal system that includes a barrier fluid system is exempt from the requirements in paragraph (b) of this section, provided the requirements specified in paragraphs (b)(2)(i) through (v) of this section are met.

(i) Each dual mechanical seal system meets the requirements of paragraphs (b)(2)(i)(A), (B), or (C) of this section.

(A) Operated with the barrier fluid at a pressure that is at all times greater than the pump stuffing box pressure; or

(B) Equipped with a barrier fluid degassing reservoir that is routed to a process or fuel gas system or connected by a closed vent system to a control device that complies with the requirements of paragraph (e) of this section; or

(C) Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.

(ii) The barrier fluid system is in heavy liquid service or does not have the potential to emit methane or VOC.

(iii) Each barrier fluid system is equipped with a sensor that will detect failure of the seal system, the barrier fluid system, or both.

(iv) Each pump is checked according to the requirements in paragraph (b)(1) of this section.

(v) Each sensor meets the requirements in paragraphs (b)(2)(v)(A) through (C) of this section.

(A) Each sensor as described in paragraph (b)(2)(iii) of this section is checked daily or is equipped with an audible alarm.

(B) You determine, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both.

(C) If the sensor indicates failure of the seal system, the barrier fluid system, or both, based on the criterion established in paragraph (b)(2)(v)(B) of this section, a leak is detected.

(3) Any pump that is designated, as described in § 60.5421b(b)(12), for no detectable emissions, as indicated by an instrument reading of less than 500 ppmv above background, is exempt from the requirements of paragraphs (b) introductory text, (b)(1), and (2) of this section if the pump:

(i) Has no externally actuated shaft penetrating the pump housing;

(ii) Is demonstrated to be operating with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background as measured by the methods specified in § 60.5403b; and

(iii) Is tested for compliance with paragraph (b)(3)(ii) of this section initially upon designation, annually, and at other times requested by the Administrator.

(4) If any pump is equipped with a closed vent system capable of capturing and transporting any leakage from the seal or seals to a process, fuel gas system, or a control device that complies with the requirements of paragraph (e) of this section, it is exempt from paragraphs (b), (b)(1) through (3) of this section, and the repair requirements of paragraph (i) of this section.

(5) Any pump that is designated, as described in § 60.5421b(b)(13), as an unsafe-to-monitor pump is exempt from the inspection and monitoring requirements of paragraphs (b) introductory text, (b)(1), and (b)(2)(iv) and (v) of this section if the conditions in paragraphs (b)(5)(i) and (ii) of this section are met.

(i) You demonstrate that the pump is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph (b) of this section; and

(ii) You have a written plan that requires monitoring of the pump as frequently as practicable during safe-to-monitor times, but not more frequently than the periodic monitoring schedule otherwise applicable, and you repair the equipment according to the procedures in paragraph (i) of this section if a leak is detected.

(6) Any pump that is located within the boundary of an unmanned plant site is exempt from the weekly visual inspection requirements in paragraph (b)(1) and (b)(2)(iv) of this section, and the daily requirements of paragraph (b)(2)(v) of this section, provided that each pump is visually inspected as often as practicable and at least monthly.

(c) *Pressure relief devices in gas/vapor service.* You must monitor each pressure relief device quarterly using the methods specified in § 60.5403b. A leak is defined as an instrument reading of 500 ppmv or greater above background.

(1) In addition to the requirements in paragraph (c) introductory text of this section, after each pressure release, you must monitor each pressure relief device within 5 calendar days after each pressure release to detect leaks. A leak is detected if an instrument reading of 500 ppmv or greater is provided using the methods specified in § 60.5403b(b).

(2) Any pressure relief device that is located in a nonfractionating plant that is monitored only by non-plant personnel may be monitored after a pressure release the next time the monitoring personnel are onsite or within 30 calendar days after a pressure release, whichever is sooner, instead of within 5 calendar days as specified in paragraph (c)(1) of this section.

(3) No pressure relief device described in paragraph (c)(2) of this section may be allowed to operate for more than 30 calendar days after a pressure release without monitoring.

(4) Any pressure relief device that is routed to a process or fuel gas system or equipped with a closed vent system capable of capturing and transporting leakage through the pressure relief device to a control device as described in paragraph (e) of this section is exempt from the requirements of paragraph (c) introductory text and (c)(1) of this section.

(5) Pressure relief devices equipped with a rupture disk are exempt from the requirements of paragraphs (c)(1) and (2) of this section provided you install a new rupture disk upstream of the pressure relief device as soon as practicable, but no later than 5 calendar days after each pressure release, except as provided in paragraph (i)(6) of this section.

(d) *Open-ended valves or lines.* Each open-ended valve or line must be equipped with a cap, blind flange, plug, or a second valve, except as provided in paragraphs (d)(4) and (5) of this section. The cap, blind flange, plug, or second valve must seal the open end of the valve or line at all times except during operations requiring process fluid flow through the open-ended valve or line.

(1) If evidence of a leak is found at any time by AVO, or any other detection method, a leak is detected and must be repaired in accordance with paragraph (i) of this section. A leak is defined as an instrument reading of 500 ppmv or greater if Method 21 of appendix A-7 to this part is used.

(2) Each open-ended valve or line equipped with a second valve must be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed.

(3) When a double block-and-bleed system is being used, the bleed valve or line may remain open during operations that require venting the line between the block valves but shall remain closed at all other times.

(4) Open-ended valves or lines in an emergency shutdown system which are designed to open automatically in the event of a process upset are exempt from the requirements of paragraphs (d) introductory text, and (d)(1) through (3) of this section.

(5) Open-ended valves or lines containing materials which would autocatalytically polymerize or would present an explosion, serious overpressure, or other safety hazard if capped or equipped with a double block-and-bleed system as specified in paragraphs (d) introductory text, (d)(2), and (3) of this section are exempt from the requirements of this section.

(e) *Closed vent systems and control devices.* Closed vent systems used to comply with the equipment leak provisions of this section must comply with the requirements in §§ 60.5411b and 60.5416b. Control devices used to comply with the equipment leak provisions of this section must comply with the requirements in §§ 60.5412b, 60.5415b(f), and 60.5417b.

(f) *Valves in gas/vapor and light liquid service.* You must monitor each valve in gas/vapor and in light liquid service quarterly to detect leaks by the methods specified in § 60.5403b, except as provided in paragraphs (f)(3) through (5) of this section.

(1) A valve that begins operation in gas/vapor service or in light liquid service after the initial startup date for the process unit must be monitored for the first time within 90 days after the end of its startup period to ensure

proper installation, except for a valve that replaces a leaking valve and except as provided in paragraphs (f)(3) through (5) of this section.

(2) An instrument reading of 500 ppmv or greater is a leak. You must repair each leaking valve according to the requirements in paragraph (i) of this section.

(3) Any valve that is designated, as described in § 60.5421b(b)(12), for no detectable emissions, as indicated by an instrument reading of less than 500 ppmv above background, is exempt from the monitoring requirements of paragraph (f) of this section if the valve:

(i) Has no externally actuating mechanism in contact with the process fluid;

(ii) Is operated with emissions less than 500 ppmv above background as determined by the methods specified in § 60.5403b; and

(iii) Is tested for compliance with paragraph (f)(3)(ii) of this section initially upon designation, annually, and at other times requested by the Administrator.

(4) Any valve that is designated, as described in § 60.5421b(b)(13), as an unsafe-to-monitor valve is exempt from the monitoring requirements of paragraph (f) of this section if the requirements in paragraphs (f)(4)(i) and (ii) of this section are met.

(i) You demonstrate that the valve is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph (f) of this section; and

(ii) You have a written plan that requires monitoring of the valve as frequently as practicable during safe-to-monitor times, but not more frequently than the periodic monitoring schedule otherwise applicable, and you repair the equipment according to the procedures in paragraph (i) of this section if a leak is detected.

(5) Any valve that is designated, as described in § 60.5421b(b)(14), as a difficult-to-monitor valve is exempt from the monitoring requirements of paragraph (f) of this section if the requirements in paragraph (f)(5)(i) through (iii) of this section are met.

(i) You demonstrate that the valve cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.

(ii) The process unit within which the valve is located has less than 3.0 percent of its total number of valves designated as difficult-to-monitor.

(iii) You have a written plan that requires monitoring of the at least once per calendar year.

(g) *Pumps, valves, and connectors in heavy liquid service and pressure relief devices in light liquid or heavy liquid service.* If evidence of a potential leak is found at any time by AVO, or any other detection method, you must comply with either paragraph (g)(1) or (2) of this section.

(1) You must monitor the equipment within 5 calendar days by the method specified in § 60.5403b and repair any leaks detected according to paragraph (i) of this section. An instrument reading of 10,000 ppmv or greater is defined as a leak.

(2) You must designate the AVO, or other indication of a leak as a leak and repair the leak according to paragraph (i) of this section.

(h) *Connectors in gas/vapor service and in light liquid service.* You must initially monitor all connectors in the process unit for leaks by the later of either 12 months after the compliance date or 12 months after initial startup. If all connectors in the process unit have been monitored for leaks prior to the compliance date, no initial monitoring is required provided either no process changes have been made since the monitoring or the owner or

operator can determine that the results of the monitoring, with or without adjustments, reliably demonstrate compliance despite process changes. If required to monitor because of a process change, you are required to monitor only those connectors involved in the process change.

- (1) You must monitor all connectors in gas/vapor service and all connectors in light liquid service annually, except as provided in § 60.5399b, paragraph (e) of this section or paragraph (h)(2) of this section. If an instrument reading greater than or equal to 500 ppmv is measured, a leak is detected.
- (2) Any connector that is designated, as described in § 60.5421b(b)(13), as an unsafe-to-monitor connector is exempt from the requirements of paragraphs (h) introductory text and (h)(1) of this section if the requirements of paragraphs (h)(2)(i) and (ii) of this section are met.
 - (i) You demonstrate the connector is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraphs (h) introductory text and (h)(1) of this section; and
 - (ii) You have a written plan that requires monitoring of the connector as frequently as practicable during safe-to-monitor times, but not more frequently than the periodic monitoring schedule otherwise applicable, and you repair the equipment according to the procedures in paragraph (i) of this section if a leak is detected.
- (3) Inaccessible, ceramic, or ceramic-line connectors.
 - (i) Any connector that is inaccessible or that is ceramic or ceramic-lined (*e.g.*, porcelain, glass, or glass-lined), is exempt from the monitoring requirements of paragraphs (h) and (h)(1) of this section, from the leak repair requirements of paragraph (i) of this section, and from the recordkeeping and reporting requirements of §§ 60.5421b and 60.5422b. An inaccessible connector is one that meets any of the specifications in paragraphs (h)(3)(i)(A) through (F) of this section, as applicable.
 - (A) Buried.
 - (B) Insulated in a manner that prevents access to the connector by a monitor probe.
 - (C) Obstructed by equipment or piping that prevents access to the connector by a monitor probe.
 - (D) Unable to be reached from a wheeled scissor-lift or hydraulic-type scaffold that would allow access to connectors up to 7.6 meters (25 feet) above the ground.
 - (E) Inaccessible because it would require elevating monitoring personnel more than 2 meters (7 feet) above a permanent support surface or would require the erection of scaffold.
 - (F) Not able to be accessed at any time in a safe manner to perform monitoring. Unsafe access includes, but is not limited to, the use of a wheeled scissor-lift on unstable or uneven terrain, the use of a motorized man-lift basket in areas where an ignition potential exists, or access would require near proximity to hazards such as electrical lines or would risk damage to equipment.
 - (ii) If any inaccessible, ceramic, or ceramic-lined connector is observed by AVO or other means to be leaking, the indications of a leak to the atmosphere by AVO or other means must be eliminated as soon as practicable.
- (4) Connectors which are part of an instrumentation systems and inaccessible, ceramic, or ceramic-lined connectors meeting the provisions of paragraph (h)(3) of this section, are not subject to the recordkeeping requirements of § 60.5421b(b)(1).

(i) *Repair requirements.* When a leak is detected, comply with the requirements of paragraphs (i)(1) through (5) of this section, except as provided in paragraph (i)(6) of this section.

(1) A weatherproof and readily visible identification tag, marked with the equipment identification number, must be attached to the leaking equipment. The identification tag on the equipment may be removed after it has been repaired.

(2) A first attempt at repair must be made as soon as practicable, but no later than 5 calendar days after the leak is detected.

(i) First attempts at repair for pumps in light liquid or heavy liquid service include, but are not limited to, the practices described in paragraphs (i)(2)(i)(A) and (B) of this section, where practicable.

(A) Tightening the packing gland nuts.

(B) Ensuring that the seal flush is operating at design pressure and temperature.

(ii) For each valve where a leak is detected, you must comply with paragraph (i)(2)(ii)(A), (B), or (C) of this section, unless you meet the requirements of paragraph (i)(2)(ii)(D) of this section.

(A) Repack the existing valve with a low-e packing.

(B) Replace the existing valve with a low-e valve; or

(C) Perform a drill and tap repair with a low-e injectable packing.

(D) An owner or operator is not required to utilize a low-e valve or low-e packing to replace or repack a valve if the owner or operator demonstrates that a low-e valve or low-e packing is not technically feasible. Low-e valve or low-e packing that is not suitable for its intended use is considered to be technically infeasible. Factors that may be considered in determining technical infeasibility include: retrofit requirements for installation (e.g., re-piping or space limitation), commercial unavailability for valve type, or certain instrumentation assemblies.

(3) Repair of leaking equipment must be completed within 15 calendar days after detection of each leak, except as provided in paragraph (i)(4), (5), or (6) of this section.

(4) If the repair for visual indications of liquids dripping for pumps in light liquid service can be made by eliminating visual indications of liquids dripping, you must make the repair within 5 calendar days of detection.

(5) If the repair for AVO or other indication of a leak for open-ended lines or valves; pumps, valves, or connectors in heavy liquid service; or pressure relief devices in light liquid or heavy liquid service can be made by eliminating the AVO, or other indication of a potential leak, you must make the repair within 5 calendar days of detection.

(6) Delay of repair of equipment for which leaks have been detected will be allowed if repair within 15 calendar days is technically infeasible without a process unit shutdown or as specified in paragraphs (i)(6)(i) through (v) of this section. Repair of this equipment shall occur before the end of the next process unit shutdown. Monitoring to verify repair must occur within 15 calendar days after startup of the process unit.

(i) Delay of repair of equipment will be allowed for equipment which is isolated from the process, and which does not have the potential to emit methane or VOC.

(ii) Delay of repair for valves and connectors will be allowed if the conditions in paragraphs (i)(6)(ii)(A) and (B) are met.

(A) You demonstrate that emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay of repair, and

(B) When repair procedures are conducted, the purged material is collected and destroyed or recovered in a control device complying with paragraph (e) of this section.

(iii) Delay of repair for pumps will be allowed if the conditions in paragraphs (i)(6)(iii)(A) and (B) are met.

(A) Repair requires the use of a dual mechanical seal system that includes a barrier fluid system, and

(B) Repair is completed as soon as practicable, but not later than 6 months after the leak was detected.

(iv) If delay of repair is required to repack or replace the valve, you may use delay of repair. Delay of repair beyond a process unit shutdown will be allowed for a valve, if valve assembly replacement is necessary during the process unit shutdown, valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted. Delay of repair beyond the next process unit shutdown will not be allowed unless the next process unit shutdown occurs sooner than 6 months after the first process unit shutdown.

(v) When delay of repair is allowed for a leaking pump, valve, or connector that remains in service, the pump, valve, or connector may be considered to be repaired and no longer subject to delay of repair requirements if two consecutive monthly monitoring results show no leak remains.

(i) *Repair requirements.* When a leak is detected, comply with the requirements of paragraphs (i)(1) through (5) of this section, except as provided in paragraph (i)(6) of this section.

(1) A weatherproof and readily visible identification tag, marked with the equipment identification number, must be attached to the leaking equipment. The identification tag on the equipment may be removed after it has been repaired.

(2) A first attempt at repair must be made as soon as practicable, but no later than 5 calendar days after the leak is detected.

(i) First attempts at repair for pumps in light liquid or heavy liquid service include, but are not limited to, the practices described in paragraphs (i)(2)(i)(A) and (B) of this section, where practicable.

(A) Tightening the packing gland nuts.

(B) Ensuring that the seal flush is operating at design pressure and temperature.

(ii) For each valve where a leak is detected, you must comply with (h)(2)(ii)(A), (B) or (C), and (D) of this section.

(A) Repack the existing valve with a low-e packing.

(B) Replace the existing valve with a low-e valve; or

(C) Perform a drill and tap repair with a low-e injectable packing.

(D) An owner or operator is not required to utilize a low-e valve or low-e packing to replace or repack a valve if the owner or operator demonstrates that a low-e valve or low-e packing is not technically feasible. Low-e valve or low-e packing that is not suitable for its intended use is considered to be technically infeasible. Factors that may be considered in determining technical infeasibility include: retrofit requirements for installation (e.g., re-piping or space limitation), commercial unavailability for valve type, or certain instrumentation assemblies.

(3) Repair of leaking equipment must be completed within 15 calendar days after detection of each leak, except as provided in paragraph (i)(4), (5), or (6) of this section.

(4) If the repair for visual indications of liquids dripping for pumps in light liquid service can be made by eliminating visual indications of liquids dripping, you must make the repair within 5 calendar days of detection.

(5) If the repair for AVO or other indication of a leak for open-ended lines or valves; pumps, valves, or connectors in heavy liquid service; or pressure relief devices in light liquid or heavy liquid service can be made by eliminating the AVO, or other indication of a potential leak, you must make the repair within 5 calendar days of detection.

(6) Delay of repair of equipment for which leaks have been detected will be allowed if repair within 15 calendar days is technically infeasible without a process unit shutdown or as specified in paragraphs (i)(6)(i) through (v) of this section. Repair of this equipment shall occur before the end of the next process unit shutdown. Monitoring to verify repair must occur within 15 calendar days after startup of the process unit.

(i) Delay of repair of equipment will be allowed for equipment which is isolated from the process, and which does not have the potential to emit methane or VOC.

(ii) Delay of repair for valves and connectors will be allowed if the conditions in paragraphs (i)(6)(ii)(A) and (B) are met.

(A) You demonstrate that emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay of repair, and

(B) When repair procedures are conducted, the purged material is collected and destroyed or recovered in a control device complying with paragraph (e) of this section.

(iii) Delay of repair for pumps will be allowed if the conditions in paragraphs (i)(6)(iii)(A) and (B) are met.

(A) Repair requires the use of a dual mechanical seal system that includes a barrier fluid system, and

(B) Repair is completed as soon as practicable, but not later than 6 months after the leak was detected.

(iv) If delay of repair is required to repack or replace the valve, you may use delay of repair. Delay of repair beyond a process unit shutdown will be allowed for a valve, if valve assembly replacement is necessary during the process unit shutdown, valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted. Delay of repair beyond the next process unit shutdown will not be allowed unless the next process unit shutdown occurs sooner than 6 months after the first process unit shutdown.

(v) When delay of repair is allowed for a leaking pump, valve, or connector that remains in service, the pump, valve, or connector may be considered to be repaired and no longer subject to delay of repair requirements if two consecutive monthly monitoring results show no leak remains.

(j) *Initial compliance.* You must demonstrate initial compliance with the standards that apply to equipment leaks at onshore natural gas processing plants as required by § 60.5410b(h).

(k) *Continuous compliance.* You must demonstrate continuous compliance with the standards that apply to equipment leaks at onshore natural gas processing plants as required by § 60.5415b(j).

(l) *Reporting.* You must perform the reporting requirements as specified in § 60.5420b(b)(1) and (11) through (13), as applicable, and § 60.5422b.

(m) *Recordkeeping.* You must perform the recordkeeping requirements as specified in § 60.5420b(c)(8) and (10) through (13), as applicable, and § 60.5421b.

§ 60.5402b What are the exceptions to the GHG and VOC standards for process unit equipment affected facilities?

(a) You may comply with the following exceptions to the provisions of §§ 60.5400b(a) and 60.5401b(a), as applicable.

(b) Pumps in light liquid service, pressure relief devices in gas/vapor service, valves in gas/vapor and light liquid service, and connectors in gas/vapor service and in light liquid service that are located at a nonfractionating plant that does not have the design capacity to process 283,200 standard cubic meters per day (scmd) (10 million standard cubic feet per day) or more of field gas may comply with the exceptions specified in paragraphs (b)(1) or (2) of this section.

(1) You are exempt from the bimonthly OGI monitoring as required under § 60.5400b(b).

(2) You are exempt from the routine Method 21 of appendix A-7 monitoring requirements of § 60.5401b(b), (c), (f), and (h), if complying with the alternative standards of § 60.5401b.

(c) Pumps in light liquid service, pressure relief devices in gas/vapor service, valves in gas/vapor and light liquid service, and connectors in gas/vapor service and in light liquid service within a process unit that is located in the Alaskan North Slope are exempt from the monitoring requirements § 60.5400b(b) and (c) and § 60.5401b(b), (c), (f) and (h).

(d) You may use the following provisions instead of § 60.5403b(d):

(1) Equipment is in heavy liquid service if the weight percent evaporated is 10 percent or less at 150 degrees Celsius (302 degrees Fahrenheit) as determined by ASTM D86-96 (incorporated by reference, see § 60.17).

(2) Equipment is in light liquid service if the weight percent evaporated is greater than 10 percent at 150 degrees Celsius (302 degrees Fahrenheit) as determined by ASTM D86-96 (incorporated by reference, see § 60.17).

(e) Equipment that is in vacuum service, except connectors in gas/vapor and light liquid service, is excluded from the requirements of § 60.5400b(b) through (g), if it is identified as required in § 60.5421b(b)(15). Equipment that is in vacuum service is excluded from the requirements of § 60.5401b(b) through (g) if it is identified as required in § 60.5421b(b)(15).

(f) Equipment that you designate as having the potential to emit methane or VOC less than 300 hr/yr is excluded from the requirements of § 60.5400b(b) through (g) and § 60.5401b(b) through (h), if it is identified as required in § 60.5421b(b)(16) and it meets any of the conditions specified in paragraphs (f)(1) through (3) of this section.

(1) The equipment has the potential to emit methane or VOC only during startup and shutdown.

(2) The equipment has the potential to emit methane or VOC only during process malfunctions or other emergencies.

(3) The equipment is backup equipment that has the potential to emit methane or VOC only when the primary equipment is out of service.

§ 60.5403b What test methods and procedures must I use for my process unit equipment affected facilities?

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

(b) You must determine compliance with the standards in § 60.5401b as follows:

(1) Method 21 of appendix A-7 to this part shall be used to determine the presence of leaking sources. The instrument shall be calibrated before use each day of its use by the procedures specified in Method 21 of appendix A-7 to this part. The following calibration gases shall be used:

(i) Zero air (less than 10 ppmv of hydrocarbon in air); and

(ii) A mixture of methane or n-hexane and air at a concentration no more than 2,000 ppmv greater than the leak definition concentration of the equipment monitored. If the monitoring instrument's design allows for multiple calibration scales, then the lower scale shall be calibrated with a calibration gas that is no higher than 2,000 ppmv above the concentration specified as a leak, and the highest scale shall be calibrated with a calibration gas that is approximately or equal to 10,000 ppmv. If only one scale on an instrument will be used during monitoring, you need not calibrate the scales that will not be used during that day's monitoring.

(iii) Verification that your monitoring equipment meets the requirements specified in Section 6.0 of Method 21 of appendix A-7 to this part. For purposes of instrument capability, the leak definition shall be 500 ppmv or greater methane using a FID-based instrument for valves and connectors and 2,000 ppmv methane or greater for pumps. If you wish to use an analyzer other than a FID-based instrument, you must develop a site-specific leak definition that would be equivalent to 500 ppmv methane using a FID-based instrument (e.g., 10.6 eV PID with a specified isobutylene concentration as the leak definition would provide equivalent response to your compound of interest).

(2) The instrument must be calibrated before use each day of its use by the procedures specified in Method 21 of appendix A-7 to this part. At minimum, you must also conduct precision tests at the interval specified in Method 21 of appendix A-7 to this part, Section 8.1.2, and a calibration drift assessment at the end of each monitoring day. The calibration drift assessment must be conducted as specified in paragraph (b)(2)(i) of this section. Corrective action for drift assessments is specified in paragraphs (b)(2)(ii) and (iii) of this section.

(i) Check the instrument using the same calibration gas that was used to calibrate the instrument before use. Follow the procedures specified in Method 21 of appendix A-7 to this part, Section 10.1, except do not adjust the meter readout to correspond to the calibration gas value. If multiple scales are used, record the instrument reading for each scale used. Divide the arithmetic difference of the initial and post-test calibration response by the corresponding calibration gas value for each scale and multiply by 100 to express the calibration drift as a percentage.

(ii) If a calibration drift assessment shows a negative drift of more than 10 percent, then all equipment with instrument readings between the fugitive emission definition multiplied by (100 minus the percent of negative drift) divided by 100 and the fugitive emission definition that was monitored since the last calibration must be re-monitored.

(iii) If any calibration drift assessment shows a positive drift of more than 10 percent from the initial calibration value, then, at the owner/operator's discretion, all equipment with instrument readings above the fugitive emission definition and below the fugitive emission definition multiplied by (100 plus the percent of positive drift) divided by 100 monitored since the last calibration may be re-monitored.

(c) You shall determine compliance with the no detectable emission standards in § 60.5401b(b) and (f) as specified in paragraphs (c)(1) and (2) of this section.

(1) The requirements of paragraph (b) of this section shall apply.

(2) Method 21 of appendix A-7 to this part shall be used to determine the background level. All potential leak interfaces shall be traversed as close to the interface as possible. The arithmetic difference between the maximum concentration indicated by the instrument and the background level is compared with 500 ppmv for determining compliance.

(d) You shall demonstrate that a piece of equipment is in light liquid service by showing that all of the following conditions apply:

(1) The vapor pressure of one or more of the organic components is greater than 0.3 kPa at 20 °C (1.2 in H₂O at 68 °F). Standard reference texts or ASTM D2879-83, -96, or -97 (all incorporated by reference, see § 60.17) shall be used to determine the vapor pressures.

(2) The total concentration of the pure organic components having a vapor pressure greater than 0.3 kPa at 20 °C (1.2 in H₂O at 68 °F) is equal to or greater than 20 percent by weight.

(3) The fluid is a liquid at operating conditions.

(e) Samples used in conjunction with paragraphs (d) and (e) of this section shall be representative of the process fluid that is contained in or contacts the equipment, or the gas being combusted in the flare.

§ 60.5405b What standards apply to sweetening unit affected facilities?

(a) During the initial performance test required by § 60.8(b), you must achieve at a minimum, an SO₂ emission reduction efficiency (Z_i) to be determined from table 3 to this subpart based on the sulfur feed rate (X) and the sulfur content of the acid gas (Y) of the affected facility.

(b) After demonstrating compliance with the provisions of paragraph (a) of this section, you must achieve at a minimum, an SO₂ emission reduction efficiency (Z_c) to be determined from table 4 to this subpart based on the sulfur feed rate (X) and the sulfur content of the acid gas (Y) of the affected facility.

(c) You must demonstrate initial compliance with the standards that apply to sweetening unit affected facilities as required by § 60.5410b(i).

(d) You must demonstrate continuous compliance with the standards that apply to sweetening unit affected facilities as required by § 60.5415b(k).

(e) You must perform the reporting as required by § 60.5420b(a)(1), (b)(1), and § 60.5423b and the recordkeeping as required by § 60.5423b.

§ 60.5406b What test methods and procedures must I use for my sweetening unit affected facilities?

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

(b) During a performance test required by § 60.8, you must determine the minimum required reduction efficiencies (Z) of SO₂ emissions as required in § 60.5405b(a) and (b) as follows:

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

Equation 1 to paragraph (b)(1)

$$X = KQ_aY$$

Where:

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

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

Y = average H₂S concentration in acid gas feed from sweetening unit, percent by volume, expressed as a decimal.

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

= 1.331 × 10⁻³Mg/dscm, for metric units.

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

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

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

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

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

(c) You must determine the emission reduction efficiency (R) achieved by the sulfur recovery technology as follows:

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

Equation 2 to paragraph (c)(1)

$$R = (100S)/(S + E)$$

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

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

Equation 3 to paragraph (c)(3)

$$E = C_e Q_{sd} / K_1$$

Where:

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

C_e = concentration of sulfur equivalent (SO_2 + reduced sulfur), g/dscm (lb/dscf).

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

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

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

- (i) You must use Method 6 or 6C of appendix A-4 to this part to determine the SO₂ concentration. You must take eight samples of 20 minutes each at 30-minute intervals. The arithmetic average must be the concentration for the run. The concentration must be multiplied by 0.5×10^{-3} to convert the results to sulfur equivalent. In place of Method 6 of appendix A to this part, you may use ANSI/ASME PTC 19.10-1981, Part 10 (manual portion only) (incorporated by reference, see § 60.17).
- (ii) You must use Method 2 of appendix A-1 to this part to determine the volumetric flow rate of the effluent gas. A velocity traverse must be conducted at the beginning and end of each run. The arithmetic average of the two measurements must be used to calculate the volumetric flow rate (Q_{sd}) for the run. For the determination of the effluent gas molecular weight, a single integrated sample over the 4-hour period may be taken and analyzed or grab samples at 1-hour intervals may be taken, analyzed, and averaged.
- (iii) You must use Method 4 of appendix A-2 to this part for moisture content. Alternatively, you must take two samples of at least 0.10 dscm (3.5 dscf) and 10 minutes at the beginning of the 4-hour run and near the end of the time period. The arithmetic average of the two runs must be the moisture content for the run.
- (iv) You must use Method 15 of appendix A-5 to this part to determine the TRS concentration from reduction-type devices or where the oxygen content of the effluent gas is less than 1.0 percent by volume. The sampling rate must be at least 3 liters/min (0.1 ft³/min) to insure minimum residence time in the sample line. You must take sixteen samples at 15-minute intervals. The arithmetic average of all the samples must be the concentration for the run. The concentration in ppmv reduced sulfur as sulfur must be multiplied by 1.333×10^{-3} to convert the results to sulfur equivalent.
- (v) You must use Method 16A of appendix A-6 to this part or ANSI/ASME PTC 19.10-1981, Part 10 (manual portion only) (incorporated by reference, see § 60.17) to determine the reduced sulfur concentration from oxidation-type devices or where the oxygen content of the effluent gas is greater than 1.0 percent by volume. You must take eight samples of 20 minutes each at 30-minute intervals. The arithmetic average must be the concentration for the run. The concentration in ppm reduced sulfur as sulfur must be multiplied by 1.333×10^{-3} to convert the results to sulfur equivalent.
- (vi) You must use EPA Method 2 of appendix A-1 to this part to determine the volumetric flow rate of the effluent gas. A velocity traverse must be conducted at the beginning and end of each run. The arithmetic average of the two measurements must be used to calculate the volumetric flow rate (Q_{sd}) for the run. For the determination of the effluent gas molecular weight, a single integrated sample over the 4-hour period may be taken and analyzed or grab samples at 1-hour intervals may be taken, analyzed, and averaged. For the moisture content, you must take two samples of at least 0.10 dscm (3.5 dscf) and 10 minutes at the beginning of the 4-hour run and near the end of the time period. The arithmetic average of the two runs must be the moisture content for the run.

§ 60.5407b What are the requirements for monitoring of emissions and operations from my sweetening unit affected facilities?

- (a) If your sweetening unit affected facility is subject to the provisions of § 60.5405b(a) or (b) you must install, calibrate, maintain, and operate monitoring devices or perform measurements to determine the following operations information on a daily basis:
 - (1) The accumulation of sulfur product over each 24-hour period. The monitoring method may incorporate the use of an instrument to measure and record the liquid sulfur production rate or may be a procedure for measuring and recording the sulfur liquid levels in the storage vessels with a level indicator or by manual soundings, with subsequent calculation of the sulfur production rate based on the tank geometry, stored sulfur

density, and elapsed time between readings. The method must be designed to be accurate within ± 2 percent of the 24-hour sulfur accumulation.

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

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

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

(5) The required sulfur dioxide emission reduction efficiency for the 24-hour period. You must use the sulfur feed rate and the H_2S concentration in the acid gas for the 24-hour period, as applicable, to determine the required reduction efficiency in accordance with the provisions of § 60.5405b(b).

(b) Where compliance is achieved through the use of an oxidation control system or a reduction control system followed by a continually operated incineration device, you must install, calibrate, maintain, and operate monitoring devices and continuous emission monitors as follows:

(1) A continuous monitoring system to measure the total sulfur emission rate (E) of SO_2 in the gases discharged to the atmosphere. The SO_2 emission rate must be expressed in terms of equivalent sulfur mass flow rates (kg/hr (lb/hr)). The span of this monitoring system must be set so that the equivalent emission limit of § 60.5405b(b) will be between 30 percent and 70 percent of the measurement range of the instrument system.

(2) Except as provided in paragraph (b)(3) of this section: A monitoring device to measure the temperature of the gas leaving the combustion zone of the incinerator, if compliance with § 60.5405b(a) is achieved through the use of an oxidation control system or a reduction control system followed by a continually operated incineration device. The monitoring device must be certified by the manufacturer to be accurate to within ± 1 percent of the temperature being measured.

(3) When performance tests are conducted under the provision of § 60.8 to demonstrate compliance with the standards under § 60.5405b, the temperature of the gas leaving the incinerator combustion zone must be determined using the monitoring device. If the volumetric ratio of sulfur dioxide to sulfur dioxide plus total reduced sulfur (expressed as SO_2) in the gas leaving the incinerator is equal to or less than 0.98, then temperature monitoring may be used to demonstrate that sulfur dioxide emission monitoring is sufficient to determine total sulfur emissions. At all times during the operation of the facility, you must maintain the average temperature of the gas leaving the combustion zone of the incinerator at or above the appropriate level determined during the most recent performance test to ensure the sulfur compound oxidation criteria are met. Operation at lower average temperatures may be considered by the Administrator to be unacceptable operation and maintenance of the affected facility. You may request that the minimum incinerator temperature be reestablished by conducting new performance tests under § 60.8.

(4) Upon promulgation of a performance specification of continuous monitoring systems for total reduced sulfur compounds at sulfur recovery plants, you may, as an alternative to paragraph (b)(2) of this section, install, calibrate, maintain, and operate a continuous emission monitoring system for total reduced sulfur compounds

as required in paragraph (c) of this section in addition to a sulfur dioxide emission monitoring system. The sum of the equivalent sulfur mass emission rates from the two monitoring systems must be used to compute the total sulfur emission rate (E).

(c) Where compliance is achieved using a reduction control system not followed by a continually operated incineration device, you must install, calibrate, maintain, and operate a continuous monitoring system to measure the emission rate of reduced sulfur compounds as SO₂ equivalent in the gases discharged to the atmosphere. The SO₂ equivalent compound emission rate must be expressed in terms of equivalent sulfur mass flow rates (kg/hr (lb/hr)). The span of this monitoring system must be set so that the equivalent emission limit of § 60.5405b(b) will be between 30 and 70 percent of the measurement range of the system. This requirement becomes effective upon promulgation of a performance specification for continuous monitoring systems for total reduced sulfur compounds at sulfur recovery plants.

(d) For those sources required to comply with paragraph (b) or (c) of this section, you must calculate the average sulfur emission reduction efficiency achieved (R) for each 24-hour clock interval. The 24-hour interval may begin and end at any selected clock time but must be consistent. You must compute the 24-hour average reduction efficiency (R) based on the 24-hour average sulfur production rate (S) and sulfur emission rate (E), using the equation in § 60.5406b(c)(1).

(1) You must use data obtained from the sulfur production rate monitoring device specified in paragraph (a) of this section to determine S.

(2) You must use data obtained from the sulfur emission rate monitoring systems specified in paragraphs (b) or (c) of this section to calculate a 24-hour average for the sulfur emission rate (E). The monitoring system must provide at least one data point in each successive 15-minute interval. You must use at least two data points to calculate each 1-hour average. You must use a minimum of 18 1-hour averages to compute each 24-hour average.

(e) In lieu of complying with paragraphs (b) or (c) of this section, those sources with a design capacity of less than 152 Mg/D (150 LT/D) of H₂S expressed as sulfur may calculate the sulfur emission reduction efficiency achieved for each 24-hour period by:

Equation 1 to paragraph (e)

$$R = \frac{K_2 S}{X}$$

Where:

R = The sulfur dioxide removal efficiency achieved during the 24-hour period, percent.

K₂ = Conversion factor, 0.02400 Mg/D per kg/hr (0.01071 LT/D per lb/hr).

S = The sulfur production rate during the 24-hour period, kg/hr (lb/hr).

X = The sulfur feed rate in the acid gas, Mg/D (LT/D).

(f) The monitoring devices required in paragraphs (b)(1) and (3) and (c) of this section must be calibrated at least annually according to the manufacturer's specifications, as required by § 60.13(b).

(g) The continuous emission monitoring systems required in paragraphs (b)(1) and (3), and (c) of this section must be subject to the emission monitoring requirements of § 60.13. For conducting the continuous emission monitoring system performance evaluation required by § 60.13(c), Performance Specification 2 of appendix B to this part must apply, and Method 6 of appendix A-4 to this part must be used for systems required by paragraph (b) of this

section. In place of Method 6 of appendix A-4 to this part, ASME PTC 19.10-1981 (incorporated by reference, see § 60.17) may be used.

§ 60.5408b What is an optional procedure for measuring hydrogen sulfide in acid gas—Tutwiler Procedure?

The Tutwiler procedure may be found in the Gas Engineers Handbook, Fuel Gas Engineering practices, The Industrial Press, 93 Worth Street, New York, NY, 1966, First Edition, Second Printing, page 6/25 (Docket A-80-20-A, Entry II-I-67).

(a) *Sampling.* When an instantaneous sample is desired and H_2S concentration is 10 grains per 1000 cubic foot or more, a 100 ml Tutwiler burette is used. For concentrations less than 10 grains, a 500 ml Tutwiler burette and more dilute solutions are used. In principle, this method consists of titrating hydrogen sulfide in a gas sample directly with a standard solution of iodine.

(b) *Apparatus.* (See figure 1 to this section.) A 100- or 500-ml capacity Tutwiler burette, with two-way glass stopcock at bottom and three-way stopcock at top that connect either with inlet tubulature or glass-stoppered cylinder, 10 ml capacity, graduated in 0.1 ml subdivision; rubber tubing connecting burette with leveling bottle.

(c) *Reagents.*

(1) Iodine stock solution, 0.1N. Weight 12.7 g iodine, and 20 to 25 g cp potassium iodide (KI) for each liter of solution. Dissolve KI in as little water as necessary; dissolve iodine in concentrated KI solution, make up to proper volume, and store in glass-stoppered brown glass bottle.

(2) Standard iodine solution, 1 ml = 0.001771 g I. Transfer 33.7 ml of above 0.1N stock solution into a 250 ml volumetric flask; add water to mark and mix well. Then, for 100 ml sample of gas, 1 ml of standard iodine solution is equivalent to 100 grains H_2S per cubic feet of gas.

(3) Rub into a thin paste about one teaspoonful of wheat starch with a little water; pour into about a pint of boiling water; stir; let cool and decant off clear solution. Make fresh solution every few days.

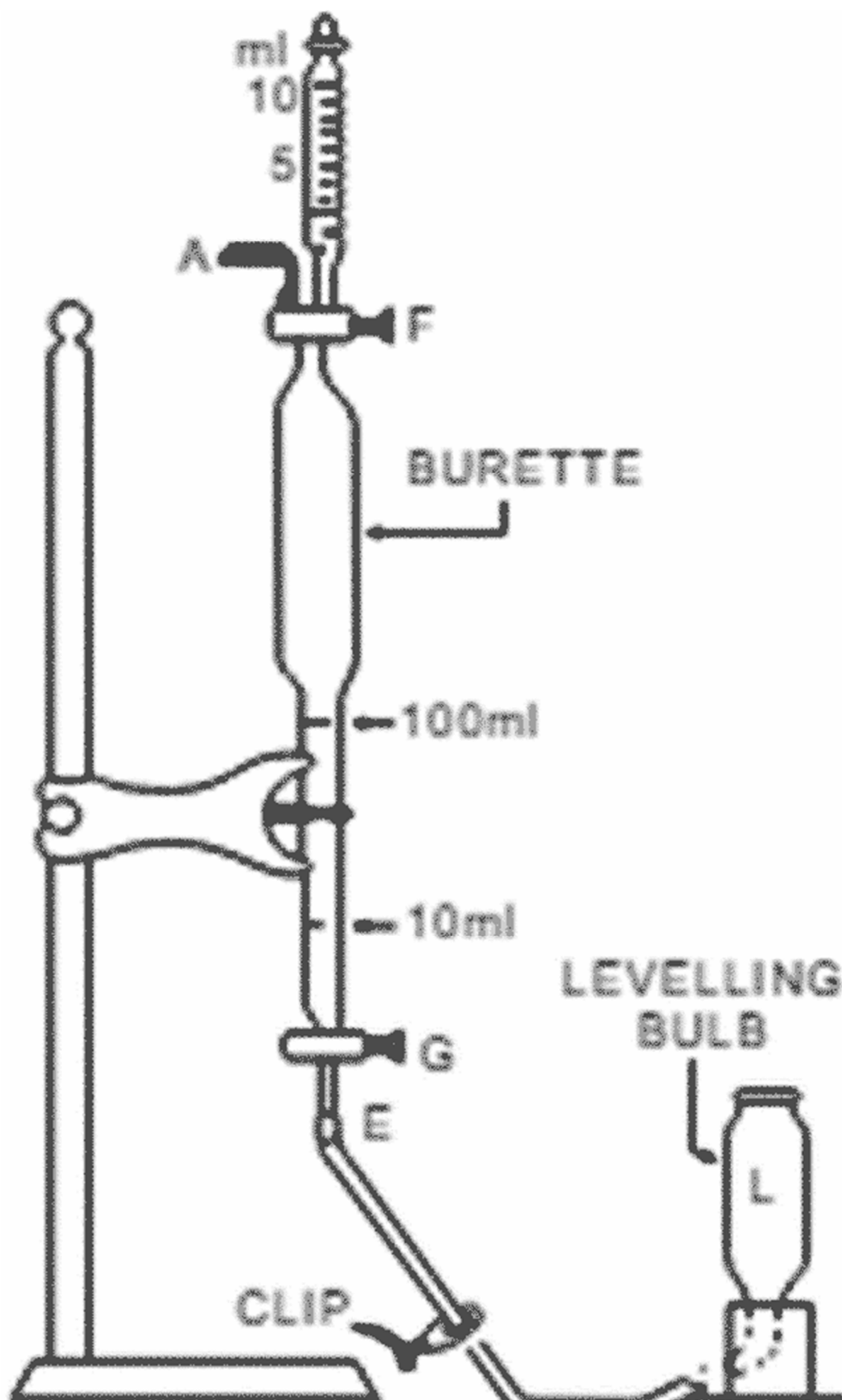
(d) *Procedure.* (Refer to figure 1 to this section.) Fill leveling bulb with starch solution. Raise (L), open cock (G), open (F) to (A), and close (F) when solutions start to run out of gas inlet. Close (G). Purge gas sampling line and connect with (A). Lower (L) and open (F) and (G). When liquid level is several ml past the 100 ml mark, close (G) and (F), and disconnect sampling tube. Open (G) and bring starch solution to 100 ml mark by raising (L); then close (G). Open (F) momentarily, to bring gas in burette to atmospheric pressure, and close (F). Open (G), bring liquid level down to 10 ml mark by lowering (L). Close (G), clamp rubber tubing near (E) and disconnect it from burette. Rinse graduated cylinder with a standard iodine solution (0.00171 g I per ml); fill cylinder and record reading. Introduce successive small amounts of iodine through (F); shake well after each addition; continue until a faint permanent blue color is obtained. Record reading; subtract from previous reading, and call difference D.

(e) *Blank testing.* (Refer to figure 1 to this section.) With every fresh stock of starch solution perform a blank test as follows: Introduce fresh starch solution into burette up to 100 ml mark. Close (F) and (G). Lower (L) and open (G). When liquid level reaches the 10 ml mark, close (G). With air in burette, titrate as during a test and up to same end point. Call ml of iodine used C. Then,

Equation 1 to paragraph (e)

$$\text{Grains } \text{H}_2\text{S per 100 cubic feet of gas} = 100 (D-C)$$

(f) *Test sensitivity.* Greater sensitivity can be attained if a 500 ml capacity Tutwiler burette is used with a more dilute (0.001N) iodine solution. Concentrations less than 1.0 grains per 100 cubic foot can be determined in this way. Usually, the starch-iodine end point is much less distinct, and a blank determination of end point, with H_2S -free gas or air, is required.



Tutwiler burette (lettered items mentioned in text).

§ 60.5410b How do I demonstrate initial compliance with the standards for each of my affected facilities?

You must determine initial compliance with the standards for each affected facility using the requirements of paragraphs (a) through (k) of this section. Except as otherwise provided in this section, the initial compliance period begins on the date specified in § 60.5370b and ends no later than 1 year after that date. The initial compliance period may be less than 1 full year.

(a) *Well completion standards for well affected facilities.* To achieve initial compliance with the GHG and VOC standards for each well completion operation conducted at your well affected facility as required by § 60.5375b, you must comply with paragraphs (a)(1) through (4) of this section.

- (1) You must submit the notification required in § 60.5420b(a)(2).
- (2) You must submit the initial annual report for your well affected facility as required in § 60.5420b(b)(1) and (2).
- (3) You must maintain a log of records as specified in § 60.5420b(c)(1)(i) through (iv) and (vii), as applicable, for each well completion operation conducted. If you meet the exemption at § 60.5375b(g) for wells with a GOR less than 300 scf per stock barrel of oil produced, you do not have to maintain the records in § 60.5420b(c)(1)(i) through (iv) and must maintain the record in § 60.5420b(c)(1)(vi). If you meet the exemption at § 60.5375b(h) for a well modified in accordance with § 60.5365b(a)(1)(ii) (*i.e.*, an existing well is hydraulically refractured), you do not need to maintain the records in § 60.5420b(c)(1)(i) through (iv) and must maintain the record in § 60.5420b(c)(1)(viii).
- (4) For each well completion affected facility subject to both § 60.5375b(a)(1) and (2), as an alternative to retaining the records specified in § 60.5420b(c)(1)(i) through (iv), you may maintain records in accordance with § 60.5420b(c)(1)(v).

(b) *Gas well liquids unloading standards for well affected facility.* To demonstrate initial compliance with the GHG and VOC standards for each gas well liquids unloading operation conducted at your gas well affected facility as required by § 60.5376b, you must comply with paragraphs (b)(1) through (4) of this section, as applicable.

- (1) You must submit the initial annual report for your well affected facility as required in § 60.5420b(b)(1) and (3).
- (2) If you comply by using a liquids unloading technology or technique that does not vent to the atmosphere according to § 60.5376b(a)(1), you must maintain the records specified in § 60.5420b(c)(2)(i).
- (3) If you comply by using a liquids unloading technology or technique that vents to the atmosphere according to § 60.5376b(a)(2), (b) and (c), you must comply with paragraphs (b)(3)(i) and (ii) of this section.
 - (i) Employ best management practices to minimize venting of methane and VOC emissions as specified in § 60.5376b(c) for each gas well liquids unloading operation.
 - (ii) Maintain the records specified in § 60.5420b(c)(2)(ii).
- (4) If you comply by using § 60.5376b(g), you must comply with paragraphs (b)(4)(i) through (vi) of this section.
 - (i) Reduce methane and VOC emissions by 95.0 percent or greater and as demonstrated by the requirements of § 60.5413b.
 - (ii) Install a closed vent system that meets the requirements of § 60.5411b(a) and (c) to capture all emissions and route all emissions to a control device that meets the conditions specified in § 60.5412b.

(iii) Conduct an initial performance test as required in § 60.5413b within 180 days after the initial gas well liquids unloading operation, or install a control device tested under § 60.5413b(d) which meets the criteria in § 60.5413b(d)(11) and (e), and comply with the continuous compliance requirements of § 60.5415b(f).

(iv) You must conduct the initial inspections required in § 60.5416b(a) and (b).

(v) You must install and operate the continuous parameter monitoring systems in accordance with § 60.5417b(a) through (i), as applicable.

(vi) You must maintain the records specified in § 60.5420b(c)(2)(iii), (c)(8) and (c)(10) through (13), as applicable and submit the reports as required by § 60.5420b(b)(11) through (13), as applicable.

(c) *Associated gas well standards for well affected facility.* To demonstrate initial compliance with the GHG and VOC standards for each associated gas well as required by § 60.5377b, you must comply with paragraphs (c)(1) through (4) of this section.

(1) If you comply with the requirements of § 60.5377b(a), you must maintain the records specified in § 60.5420b(c)(3)(i), (ii), and (iv).

(2) For associated gas wells that comply with § 60.5377b(f) based on a demonstration and certification that it is not feasible to comply with paragraphs (a)(1), (2), (3), and (4) of this section due to technical reasons in accordance with paragraph § 60.5377b(g), you must comply with paragraphs (c)(2)(i) and (ii) of this section.

(i) Document the technical reasons why it is infeasible to route recovered associated gas into a gas gathering flow line or collection system to a sales line, use it as an onsite fuel source, use it for another useful purpose that a purchased fuel or raw material would serve, or re-inject it into the well or inject it into another well, maintain the documentation in accordance with § 60.5377(g), and submit this documentation in the initial annual report as required by paragraph (c)(4) of this section.

(ii) Maintain a copy of the certification and submit the certification as required by § 60.5377b(g).

(3) If you comply with § 60.5377b(d) or (f), you must comply with paragraphs (c)(3)(i) through (vi) of this section.

(i) Reduce methane and VOC emissions by 95.0 percent or greater and as demonstrated by the requirements of § 60.5413b.

(ii) Install a closed vent system that meets the requirements of § 60.5411b(a) and (c) to capture the associated gas and route the captured associated gas to a control device that meets the conditions specified in § 60.5412b.

(iii) Conduct an initial performance test as required in § 60.5413b within 180 days after initial startup or by May 7, 2024, whichever date is later, or install a control device tested under § 60.5413b(d) which meets the criteria in § 60.5413b(d)(11) and (e) and you must comply with the continuous compliance requirements of § 60.5415b(f).

(iv) Conduct the initial inspections required in § 60.5416b(a) and (b).

(v) Install and operate the continuous parameter monitoring systems in accordance with § 60.5417b(a) through (i), as applicable.

(vi) Maintain the records specified in § 60.5420b(c)(3)(iv) and (c)(8) and (c)(10) through (13), as applicable.

(4) You must submit the initial annual report for your associated gas well as required in § 60.5420b(b)(1) and (4) and (b)(11) through (13), as applicable.

(d) *Centrifugal compressor affected facility.* To demonstrate initial compliance with the GHG and VOC standards for your centrifugal compressor affected facility that uses a wet seal as required by § 60.5380b, you must comply with paragraphs (d)(1) through (5) and paragraphs (d)(7) and (8) of this section. To demonstrate initial compliance with the GHG and VOC alternative standards for your centrifugal compressor affected facility that is a self-contained wet seal centrifugal compressor or a centrifugal compressor at the Alaska North Slope equipped with sour seal oil separator and capture system as allowed by § 60.5380b, you must comply with paragraphs (d)(6) through (8) of this section. To demonstrate initial compliance with the GHG and VOC alternative standards for your dry seal centrifugal compressor as required by § 60.5380b, you must comply with paragraphs (d)(6) through (8) of this section.

(1) You must reduce methane and VOC emissions by 95.0 percent or greater according to § 60.5380b(a)(1) and (2) and as demonstrated by the requirements of § 60.5413b, or you must route emissions to a process according to § 60.5380b(a)(3).

(2) If you use a control device to reduce emissions to comply with § 60.5380b(a)(1) and (2), you must equip the wet seal fluid degassing system with a cover that meets the requirements of § 60.5411b(b) that is connected through a closed vent system that meets the requirements of § 60.5411b(a) and (c) and is routed to a control device that meets the conditions specified in § 60.5412b. If you comply with § 60.5380b(a)(3) by routing the closed vent system to a process as an alternative to routing the closed vent system to a control device, you must equip the wet seal fluid degassing system with a cover that meets the requirements of § 60.5411b(b), and route captured vapors through a closed vent system to a process that meets the requirements of § 60.5411b(a) and (c).

(3) If you use a control device to comply with § 60.5380b(a)(1) and (2), you must conduct an initial performance test as required in § 60.5413b within 180 days after initial startup or by May 7, 2024, whichever date is later, or install a control device tested under § 60.5413b(d) which meets the criteria in § 60.5413b(d)(11) and (e) and you must comply with the continuous compliance requirements of § 60.5415b(f).

(4) If you use a control device to comply with § 60.5380b(a)(1) and (2) or comply with § 60.5380b(a)(3) by routing to a process, you must conduct the initial inspections required in § 60.5416b(a) and (b).

(5) If you use a control device to comply with § 60.5380b(a)(1) and (2), you must install and operate the continuous parameter monitoring systems in accordance with § 60.5417b(a) through (i), as applicable.

(6) You must maintain the volumetric flow rates for your centrifugal compressors as specified in paragraphs (d)(6)(i) through (iii) of this section, as applicable.

(i) For your self-contained wet seal centrifugal compressors, you must maintain the volumetric flow rate at or below 3 scfm per seal. You must conduct your initial annual volumetric measurement as required by § 60.5380b(a)(4).

(ii) For your centrifugal compressor on the Alaska North Slope equipped with sour seal oil separator and capture system, you must maintain the volumetric flow rate at or below 9 scfm per seal. You must conduct your initial annual volumetric measurement as required by § 60.5380b(a)(5).

(iii) For your dry seal centrifugal compressor, you must maintain the volumetric flow rate at or below 10 scfm per seal. You must conduct your initial annual volumetric measurement as required by § 60.5380b(a)(6).

(7) You must submit the initial annual report for your centrifugal compressor affected facility as required in § 60.5420b(b)(1) and (5) and (b)(11) through (13), as applicable.

(8) You must maintain the records as specified in § 60.5420b(c)(4) and (c)(8) through (13), as applicable.

(e) *Reciprocating compressor affected facility.* To demonstrate initial compliance with the GHG and VOC standards for each reciprocating compressor affected facility as required by § 60.5385b, you must comply with paragraphs (e)(1) through (7) of this section.

(1) If you comply with § 60.5385b by maintaining volumetric flow rate at or below 2 scfm per cylinder (or a combined cylinder volumetric flow rate greater than the number of compression cylinders multiplied by 2 scfm) as required by § 60.5385b(a), you must maintain volumetric flow rate at or below 2 scfm and you must conduct your initial annual volumetric flow rate measurement as required by § 60.5385b(a)(1).

(2) If you comply with § 60.5385b by collecting the methane and VOC emissions from your reciprocating compressor rod packing using a rod packing emissions collection system as required by § 60.5385b(d)(1), you must equip the reciprocating compressor with a cover that meets the requirements of § 60.5411b(b), route emissions to a process through a closed vent system that meets the requirements of § 60.5411b(a) and (c), and you must conduct the initial inspections required in § 60.5416b(a) and (b).

(3) If you comply with § 60.5385b(d) by collecting the emissions from your rod packing emissions collection system by using a control device to reduce VOC and methane emissions by 95.0 percent as required by § 60.5385b(d)(2), you must equip the reciprocating compressor with a cover that meets the requirements of § 60.5411b(b), route emissions to a control device that meets the conditions specified in § 60.5412b through a closed vent system that meets the requirements of § 60.5411b(a) and (c) and you must conduct the initial inspections required in § 60.5416b(a) and (b).

(4) If you comply with § 60.5385b(d)(2), you must conduct an initial performance test as required in § 60.5413b within 180 days after initial startup or by May 7, 2024, whichever date is later, or install a control device tested under § 60.5413b(d) which meets the criteria in § 60.5413b(d)(11) and (e) and you must comply with the continuous compliance requirements of § 60.5415b(f).

(5) If you comply with § 60.5385b(d)(2), you must install and operate the continuous parameter monitoring systems in accordance with § 60.5417b(a) through (i), as applicable.

(6) You must submit the initial annual report for your reciprocating compressor as required in § 60.5420b(b)(1), (6), and (11) through (13), as applicable.

(7) You must maintain the records as specified in § 60.5420b(c)(5) and (8) through (13) as applicable.

(f) *Process controller affected facility.* To demonstrate initial compliance with GHG and VOC emission standards for your process controller affected facility as required by § 60.5390b, you must comply with paragraphs (f)(1) through (5) of this section, as applicable. If you change compliance methods, you must also perform the applicable compliance demonstrations of paragraphs (f)(1) through (3) of this section again for the new compliance method, note the change in compliance method in the annual report required by § 60.5420b(b)(7)(iv), and maintain the records required by paragraph (f)(5) of this section for the new compliance method.

(1) For process controller affected facilities complying with the requirements of § 60.5390b(a), you must demonstrate that your process controller affected facility does not emit any VOC or methane to the atmosphere by meeting the requirements of paragraphs (f)(1)(i) or (ii) of this section.

(i) If you comply by routing the emissions to a process, you must meet the requirements for closed vent systems specified in paragraph (f)(3) of this section.

(ii) If you comply by using a self-contained natural gas-driven process controller, you must conduct an initial no identifiable emissions inspection as required by § 60.5416b(b).

(2) For each process controller affected facility located at a site in Alaska that does not have access to electrical power, you must demonstrate initial compliance with § 60.5390b(b)(1) and (2) or with § 60.5390b(b)(3), instead

of complying with paragraph § 60.5390b(a), by meeting the requirements specified in (f)(2)(i) through (iv) of this section for each process controller, as applicable.

(i) For each process controller in the process controller affected facility operating with a bleed rate of less than or equal to 6 scfh, you must maintain records in accordance with § 60.5420b(c)(6)(iii)(A) that demonstrate the process controller is designed and operated to achieve a bleed rate less than or equal to 6 scfh.

(ii) For each process controller in the process controller affected facility operating with a bleed rate greater than 6 scfh, you must maintain records that demonstrate that a controller with a higher bleed rate than 6 scfh is required based on a specific functional need for that controller as specified in § 60.5420b(c)(6)(iii)(B).

(iii) For each intermittent vent process controller in the process controller affected facility you must demonstrate that each intermittent vent controller does not emit to the atmosphere during idle periods by conducting initial monitoring in accordance with § 60.5390b(b)(2)(ii).

(iv) For each process controller affected facility that complies by reducing methane and VOC emissions from all controllers in the process controller affected facility by 95.0 percent in accordance with § 60.5390b(b)(3), you must comply with paragraphs (b)(2)(iv)(A) through (D) of this section.

(A) Reduce methane and VOC emissions by 95.0 percent or greater and as demonstrated by the requirements of § 60.5413b.

(B) Route all process controller affected facility emissions to a control device that meets the conditions specified in § 60.5412b through a closed vent system that meets the requirements specified in paragraph (f)(3) of this section.

(C) Conduct an initial performance test as required in § 60.5413b within 180 days after initial startup or by May 7, 2024, whichever date is later, or install a control device tested under § 60.5413b(d) which meets the criteria in § 60.5413b(d)(11) and (e) and you must comply with the continuous compliance requirements of § 60.5415b(f).

(D) Install and operate the continuous parameter monitoring systems in accordance with § 60.5417b(a) through (i), as applicable.

(3) For each closed vent system used to comply with § 60.5390b, you must meet the requirements specified in paragraphs (f)(3)(i) and (ii) of this section.

(i) Install a closed vent system that meets the requirements of § 60.5411b(a) and (c).

(ii) Conduct the initial inspections of the closed vent system and bypasses, if applicable, as required in § 60.5416b(a) and (b).

(4) You must submit the initial annual report for your process controller affected facility as required in § 60.5420b(b)(1) and (7).

(5) You must maintain the records as specified in § 60.5420b(c)(6).

(g) *Pump affected facility.* To demonstrate initial compliance with the GHG and VOC standards for your pump affected facility as required by § 60.5393b, you must comply with paragraphs (g)(1) through (4) of this section, as applicable. If you change compliance methods, you must also perform the applicable compliance demonstrations of paragraphs (g)(1) and (2) of this section again for the new compliance method, note the change in compliance method in the annual report required by § 60.5420b(b)(10)(v)(C), and maintain the records required by paragraph (g)(4) of this section for the new compliance method.

(1) For pump affected facilities complying with the requirements of § 60.5393b(a) or (b)(2) by routing emissions to a process, you must meet the requirements specified in paragraphs (g)(1)(ii) and (iv) of this section. For pump affected facilities complying with the requirements of § 60.5393b(b)(3), you must meet the requirements specified in paragraphs (g)(1)(i) through (v) of this section.

(i) Reduce methane and VOC emissions by 95.0 percent or greater and as demonstrated by the requirements of § 60.5413b.

(ii) Install a closed vent system that meets the requirements of § 60.5411b(a) and (c) to capture all emissions from all pumps in the pump affected facility and route all emissions to a process or control device that meets the conditions specified in § 60.5412b.

(iii) Conduct an initial performance test as required in § 60.5413b within 180 days after initial startup or by May 7, 2024, whichever date is later, or install a control device tested under § 60.5413b(d) which meets the criteria in § 60.5413b(d)(11) and (e) and you must comply with the continuous compliance requirements of § 60.5415b(f).

(iv) Conduct the initial inspections of the closed vent system and bypasses, if applicable, as required in § 60.5416b(a) and (b).

(v) Install and operate the continuous parameter monitoring systems in accordance with § 60.5417b(a) through (i), as applicable.

(2) Submit the certifications specified in paragraphs (g)(2)(i) through (iii) of this section, as applicable.

(i) The certification required by § 60.5393b(b)(5) that there is no vapor recovery unit on site and that there is a control device on site, but it does not achieve a 95.0 percent emissions reduction.

(ii) The certification required by § 60.5393b(b)(6) that there is no control device or process available on site.

(iii) The certification required by § 60.5393b(b)(7) that it is technically infeasible to capture and route the pump affected facility emissions to a process or an existing control device.

(3) You must submit the initial annual report for your pump affected facility as specified in § 60.5420b(b)(1), (10), and (b)(11) through (13), as applicable.

(4) You must maintain the records for your pump affected facility as specified in § 60.5420b(c)(8) and (c)(10) through (13), as applicable, and (c)(15).

(h) *Process unit equipment affected facility.* To achieve initial compliance with the GHG and VOC standards for process unit equipment affected facilities as required by § 60.5400b, you must comply with paragraphs (h)(1) through (4) and (h)(11) through (15) of this section, unless you meet and comply with the exception in § 60.5402b(b), (e), or (f) or meet the exemption in § 60.5402b(c). If you comply with the GHG and VOC standards for process unit equipment affected facilities using the alternative standards in § 60.5401b, you must comply with paragraphs (h)(5) through (15) of this section, unless you meet the exemption in § 60.5402b(b) or (c) or the exception in § 60.5402b(e) or (f).

(1) You must conduct monitoring for each pump in light liquid service, pressure relief device in gas/vapor service, valve in gas/vapor or light liquid service and connector in gas/vapor or light liquid service as required by § 60.5400b(b).

(2) You must conduct monitoring as required by § 60.5400b(c) for each pump in light liquid service.

(3) You must conduct monitoring as required by § 60.5400b(d) for each pressure relief device in gas/vapor service.

- (4) You must comply with the equipment requirements for each open-ended valve or line as required by § 60.5400b(e).
- (5) You must conduct monitoring for each pump in light liquid service as required by § 60.5401b(b).
- (6) You must conduct monitoring for each pressure relief device in gas/vapor service as required by § 60.5401b(c).
- (7) You must comply with the equipment requirements for each open-ended valve or line as required by § 60.5401b(d).
- (8) You must conduct monitoring for each valve in gas/vapor or light liquid service as required by § 60.5401b(f).
- (9) You must conduct monitoring for each pump, valve, and connector in heavy liquid service and each pressure relief device in light liquid or heavy liquid service as required by § 60.5401b(g).
- (10) You must conduct monitoring for each connector in gas/vapor or light liquid service as required by § 60.5401b(h).
- (11) For each pump equipped with a dual mechanical seal system that degasses the barrier fluid reservoir to a process or a control device, each pump which captures and transports leakage from the seal or seals to a process or a control device, or each pressure relief device which captures and transports leakage through the pressure relief device to a process or a control device, you must meet the requirements of paragraph (h)(11)(i) through (vi) of this section.
 - (i) Reduce methane and VOC emissions by 95.0 percent or greater and as demonstrated by the requirements of § 60.5413b or route to a process.
 - (ii) Install a closed vent system that meets the requirements of § 60.5411b(a) and (c) to capture all emissions from each pump equipped with a dual mechanical seal system that degasses the barrier fluid reservoir, each pump which captures and transports leakage from the seal or seals, or each pressure relief device which captures and transports leakage through the pressure relief device and route all emissions to a process or to a control device that meets the conditions specified in § 60.5412b.
 - (iii) If routing to a control device, conduct an initial performance test as required in § 60.5413b within 180 days after initial startup or by May 7, 2024, whichever date is later, or install a control device tested under § 60.5413b(d) which meets the criteria in § 60.5413b(d)(11) and (e), and you must comply with the continuous compliance requirements of § 60.5415b(f).
 - (iv) Conduct the initial inspections of the closed vent system and bypasses, if applicable, as required in § 60.5416b(a) and (b).
 - (v) Install and operate the continuous parameter monitoring systems in accordance with § 60.5417b(a) through (i), as applicable.
 - (vi) Maintain the records as required by § 60.5420b(c)(8) and (c)(10) through (c)(13), as applicable and submit the reports as required by § 60.5420b(b)(11) through (13), as applicable.
- (12) You must tag and repair each identified leak as required in § 60.5400b(h) or § 60.5401b(i), as applicable.
- (13) You must submit the notice required by § 60.5420b(a)(1).
- (14) You must submit the initial semiannual report and subsequent semiannual report as required by § 60.5422b.
- (15) You must maintain the records specified by § 60.5421b.

(i) *Sweetening unit affected facility.* To achieve initial compliance with the SO₂ standard for your sweetening unit affected facility as required by § 60.5405b, you must comply with paragraphs (i)(1) through (14) of this section.

(1) You must conduct an initial performance test as required by § 60.8 and according to the requirements of § 60.5406b.

(2) You must determine the minimum required initial reduction efficiency of SO₂ emissions (Z_i) as required by § 60.5406b(b).

(3) You must determine the emission reduction efficiency (R) achieved by your sulfur reduction technology using the procedures in § 60.5406b(c)(1) through (4).

(4) You must demonstrate compliance with the standard as required by § 60.5405b(a) by comparing the minimum required SO₂ emission reduction efficiency (Z_i) to the emission reduction efficiency achieved by the sulfur recovery technology (R), where R must be greater than or equal to Z_i .

(5) You must install, calibrate, maintain, and operate monitoring devices or perform measurements to determine the accumulation of sulfur product, the H₂S concentration, the average acid gas flow rate, and the sulfur feed rate in accordance with § 60.5407b(a).

(6) You must determine the required SO₂ emissions reduction efficiency each 24-hour period in accordance with § 60.5407b(a), (d), and (e), as applicable.

(7) You must install, calibrate, maintain, and operate monitoring devices and continuous emission monitors in accordance with § 60.5407b(b), (f), and (g), if you use an oxidation control system or a reduction control system followed by an incineration device.

(8) You must continuously operate the incineration device if you use an oxidation control system, or a reduction control system followed by an incineration device.

(9) You must install, calibrate, maintain, and operate a continuous monitoring system to measure the emission rate of reduced sulfur compounds in accordance with § 60.5407b(c), (f), and (g), if you use a reduction control system not followed by an incineration device.

(10) You must submit the notification required by § 60.5420b(a)(1).

(11) You must submit the initial annual report required by § 60.5423b(b).

(12) You must submit the performance test report in accordance with the requirements of § 60.5420b(b)(12).

(13) You must submit the annual excess emissions reports required by § 60.5423b(d), if applicable.

(14) You must maintain the records required by § 60.5423b(a), (e) and (f), as applicable.

(j) *Storage vessel affected facility.* To achieve initial compliance with the GHG and VOC standards for each storage vessel affected facility as required by § 60.5395b, you must comply with paragraphs (j)(1) through (9) of this section. To achieve initial compliance with the GHG and VOC standards for each storage vessel affected facility that complies by using a floating roof in accordance with § 60.5395b(b)(2), you must comply with paragraphs (j)(1) and (10) of this section.

(1) You must determine the potential for methane and VOC emissions as specified in § 60.5365b(e)(2).

(2) You must reduce methane and VOC emissions by 95.0 percent or greater according to § 60.5395b(a) and as demonstrated by the requirements of § 60.5413b or route to a process.

(3) If you use a control device to reduce emissions, you must equip each storage vessel in the storage vessel affected facility with a cover that meets the requirements of § 60.5411b(b), install a closed vent system that meets the requirements of § 60.5411b(a) and (c) to capture all emissions from the storage vessel affected

facility, and route all emissions to a control device that meets the conditions specified in § 60.5412b. If you route emissions to a process, you must equip each storage vessel in the storage vessel affected facility with a cover that meets the requirements of § 60.5411b(b), install a closed vent system that meets the requirements of § 60.5411b(a) and (c) to capture all emissions from the storage vessel affected facility, and route all emissions to a process.

(4) If you use a control device to reduce emissions, you must conduct an initial performance test as required in § 60.5413b within 180 days after initial startup or within 180 days of May 7, 2024, whichever date is later, or install a control device tested under § 60.5413b(d) which meets the criteria in § 60.5413b(d)(11) and (e), and you must comply with the continuous compliance requirements of § 60.5415b(f).

(5) You must conduct the initial inspections of the closed vent system and bypasses, if applicable, as required in § 60.5416b(a) and (b).

(6) You must install and operate the continuous parameter monitoring systems in accordance with § 60.5417b(a) through (i), as applicable.

(7) You must maintain the records as required by § 60.5420b(c)(8) through (13), as applicable and submit the reports as required by § 60.5420b(b)(11) through (13), as applicable.

(8) You must submit the initial annual report for your storage vessel affected facility required by § 60.5420b(b)(1) and (8).

(9) You must maintain the records required for your storage vessel affected facility, as specified in § 60.5420b(c)(7) for each storage vessel affected facility.

(10) For each storage vessel affected facility that complies by using a floating roof, you must meet the requirements of § 60.112b(a)(1) or (2) and the relevant monitoring, inspection, recordkeeping, and reporting requirements in subpart Kb of this part. You must submit a statement that you are complying with § 60.112b(d)(a)(1) or (2) in accordance with § 60.5395b(b)(2) with the initial annual report specified in § 60.5420b(b)(1) and (8).

(k) *Fugitive emission components affected facility.* To achieve initial compliance with the GHG and VOC standards for fugitive emissions components affected facilities as required by § 60.5397b, you must comply with paragraphs (k)(1) through (5) of this section.

(1) You must develop a fugitive emissions monitoring plan as required in § 60.5397b(b), (c), and (d).

(2) You must conduct an initial monitoring survey as required in § 60.5397b(e) and (f).

(3) You must repair each identified source of fugitive emissions for each affected facility as required in § 60.5397b(h).

(4) You must submit the initial annual report for each fugitive emissions components affected facility as required in § 60.5420b(b)(1) and (9).

(5) You must maintain the records specified in § 60.5420b(c)(14).

§ 60.5411b What additional requirements must I meet to determine initial compliance for my covers and closed vent systems?

For each cover or closed vent system at your well, centrifugal compressor, reciprocating compressor, process controller, pump, storage vessel, and process unit equipment affected facilities, you must comply with the applicable requirements of paragraphs (a) through (c) of this section.

(a) *Closed vent system requirements.*

(1) Reciprocating compressor rod packing, process controllers, and pumps. You must design the closed vent system to capture and route all gases, vapors, and fumes to a process.

(2) Associated gas wells, centrifugal compressors, process controllers in Alaska, pumps complying with § 60.5393b(b)(1), storage vessels, and process unit equipment. You must design the closed vent system to capture and route all gases, vapors, and fumes to a process or a control device that meets the requirements specified in § 60.5412b(a) through (d) of this section. For pumps complying with § 60.5393b(b)(3), you must design the closed vent system to capture and route all gases, vapors, and fumes to a control device that meets the requirements specified in § 60.5412b(a) through (d) of this section.

(3) Beginning January 22, 2027, or upon startup, whichever is later, you must design and operate the closed vent system with no identifiable emissions as demonstrated by § 60.5416b(a) and (b).

(4) Bypass devices. You must meet the requirements specified in paragraphs (a)(4)(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 being routed to a process.

(i) Except as provided in paragraph (a)(4)(ii) of this section, you must comply with either paragraph (a)(4)(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. The flow indicator must be capable of taking periodic readings as specified in § 60.5416b(a)(4)(i) and sound an alarm, or initiate 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, and sent to the atmosphere. You must maintain records of each time the alarm is activated according to § 60.5420b(c)(10).

(B) You must secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

(ii) Low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and safety devices are not subject to the requirements of paragraph (a)(4)(i) of this section.

(b) *Cover requirements for storage vessels and centrifugal compressors, and reciprocating compressors.*

(1) The cover and all openings on the cover (*e.g.*, access hatches, sampling ports, pressure relief devices and gauge wells) shall form a continuous impermeable barrier over the entire surface area of the liquid in the storage vessel or centrifugal compressor wet seal fluid degassing system, or reciprocating compressor rod packing emissions collection system.

(2) Each cover opening shall be secured in a closed, sealed position (*e.g.*, covered by a gasketed lid or cap) whenever material is in the unit on which the cover is installed except during those times when it is necessary to use an opening as follows:

(i) To add material to, or remove material from the unit (this includes openings necessary to equalize or balance the internal pressure of the unit following changes in the level of the material in the unit);

(ii) To inspect or sample the material in the unit;

(iii) To inspect, maintain, repair, or replace equipment located inside the unit; or

(iv) To vent liquids, gases, or fumes from the unit through a closed vent system designed and operated in accordance with the requirements of paragraph (a) of this section to a control device or to a process.

(3) Each storage vessel thief hatch shall be equipped, maintained and operated with a weighted mechanism or equivalent, to ensure that the lid remains properly seated and sealed under normal operating conditions,

including such times when working, standing/breathing, and flash emissions may be generated. You must select gasket material for the hatch based on composition of the fluid in the storage vessel and weather conditions.

(4) Beginning January 22, 2027 or upon startup, whichever is later, you must design and operate the cover with no identifiable emissions as demonstrated by § 60.5416b(a) and (b), except when operated as provided in paragraphs (b)(2)(i) through (iv) of this section.

(c) Design requirements.

(1) You must conduct an assessment that the closed vent system is of sufficient design and capacity to ensure that all gases, vapors, and fumes from the affected facility are routed to the control device or process and that the control device or process is of sufficient design and capacity to accommodate all emissions from the affected facility. The assessment must be certified by a qualified professional engineer or an in-house engineer with expertise on the design and operation of the closed vent system in accordance with paragraphs (c)(1)(i) and (ii) of this section.

(i) You must provide the following certification, signed and dated by a qualified professional engineer or an in-house engineer: "I certify that the closed vent system design and capacity assessment was prepared under my direction or supervision. I further certify that the closed vent system design and capacity assessment was conducted, and this report was prepared pursuant to the requirements of subpart OOOOb of this part. Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete."

(ii) The assessment shall be prepared under the direction or supervision of a qualified professional engineer or an in-house engineer who signs the certification in paragraph (c)(1)(i) of this section.

§ 60.5412b What additional requirements must I meet for determining initial compliance of my control devices?

You must meet the requirements of paragraphs (a) and (b) of this section for each control device used to comply with the emissions standards for your well, centrifugal compressor, reciprocating compressor, storage vessel, process controller, pump, or process unit equipment affected facility. If you use a carbon adsorption system as a control device to meet the requirements of paragraph (a)(2) of this section, you also must meet the requirements in paragraph (c) of this section.

(a) Each control device used to meet the emissions reduction standard in § 60.5377b(d) or (f) for your associated gas well at a well affected facility; § 60.5376b(g) for your well affected facility gas well that unloads liquids; § 60.5380b(a)(1) or (9) for your centrifugal compressor affected facility; § 60.5385b(d)(2) for your reciprocating compressor affected facility; § 60.5395b(a)(2) for your storage vessel affected facility; § 60.5390b(b)(3) for your process controller affected facility in Alaska; § 60.5393b(b)(3) for your pumps affected facility; or either § 60.5400b(f) or § 60.5401b(e) for your process equipment affected facility must be installed according to paragraphs (a)(1) through (3) of this section. As an alternative to paragraph (a)(1) of this section, you may install a combustion control device model tested under § 60.5413b(d), which meets the criteria in § 60.5413b(d)(11) and which meets the initial and continuous compliance requirements in § 60.5413b(e).

(1) Each enclosed combustion device (e.g., thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) must be designed and operated in accordance with paragraph (a)(1)(i) of this section, meet one of the operating limits specified in paragraphs (a)(1)(ii) through (v) of this section, and except for boilers and process heaters meeting the requirements of paragraph (a)(1)(iii) of this section and catalytic vapor incinerators meeting the requirements of paragraph (a)(1)(v) of this section, meet the operating limits specified in paragraphs (a)(1)(vi) through (ix) of this section. Alternatively, the enclosed combustion device must meet the requirements specified in paragraph (d) of this section.

(i) You must reduce the mass content of methane and VOC in the gases vented to the device by 95.0 percent by weight or greater or reduce the concentration of total organic compounds (TOC) in the exhaust gases at the outlet to the device to a level equal to or less than 275 ppmv as propane on a wet basis corrected to 3 percent oxygen as determined in accordance with the requirements of § 60.5413b(b), with the exceptions noted in § 60.5413b(a).

(ii) For an enclosed combustion device for which you demonstrate during the performance test conducted under § 60.5413b(b) that combustion zone temperature is an indicator of destruction efficiency, you must operate at or above the minimum temperature established during the most recent performance test. During the performance test conducted under § 60.5413b(b), you must continuously record the temperature of the combustion zone and average the temperature for each test run. The established minimum temperature limit is the average of the test run averages.

(iii) For an enclosed combustion device which is a boiler or process heater, you must introduce the vent stream into the flame zone of the boiler or process heater and introduce the vent stream with the primary fuel or use the vent stream as the primary fuel.

(iv) For an enclosed combustion device other than those meeting the operating limits in paragraphs (a)(1)(ii), (iii), and (v) of this section, if the enclosed combustion device is unassisted or pressure-assisted, you must maintain the net heating value (NHV) of the gas sent to the enclosed combustion device at or above the applicable limits specified in paragraphs (a)(1)(iv)(A) and (B) of this section. If the enclosed combustion device is steam-assisted or air-assisted, you must meet the applicable limits specified in paragraphs (a)(1)(iv)(C) and (D) of this section, as appropriate.

(A) For enclosed combustion devices that do not use assist gas or pressure-assisted burner tips to promote mixing at the burner tip, 200 British thermal units (Btu) per standard cubic feet (Btu/scf).

(B) For enclosed combustion devices that use pressure-assisted burner tips to promote mixing at the burner tip, 800 Btu/scf.

(C) For steam-assisted and air-assisted enclosed combustion devices, maintain the combustion zone NHV (NHV_{cz}) at or above 270 Btu/scf.

(D) For enclosed combustion devices with perimeter assist air, maintain the NHV dilution parameter (NHV_{dil}) at or above 22 British thermal units per square foot (Btu/sqft). If the only assist air provided to the enclosed combustion control device is perimeter assist air intentionally entrained in lower and/or upper steam at the burner tip and the effective diameter is 9 inches or greater, you are only required to comply with the NHV_{cz} limit specified in paragraph (a)(1)(iv)(C) of this section.

(v) For an enclosed combustion device which is a catalytic vapor incinerator, you must operate the catalytic vapor incinerator at or above the minimum temperature of the catalyst bed inlet and at or above the minimum temperature differential between the catalyst bed inlet and the catalyst bed outlet established in accordance with § 60.5417b(f) and as determined in your performance test conducted in accordance with § 60.5413b(b).

(vi) Unless you have an enclosed combustion device with pressure-assisted burner tips to promote mixing at the burner tip, you must operate each enclosed combustion device at or below the maximum inlet gas flow rate established in accordance with § 60.5417b(f) and as determined in your performance test conducted in accordance with § 60.5413b(b).

(vii) You must operate the combustion control device at or above the minimum inlet gas flow rate established in accordance with § 60.5417b(f).

(viii) After January 22, 2027, you must install and operate a continuous burning pilot or combustion flame. After January 22, 2027, an alert must be sent to the nearest control room whenever the pilot or combustion flame is unlit.

(ix) You must operate the enclosed combustion device with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period. A visible emissions test using section 11 of Method 22 of appendix A-7 to this part 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 or once the amount of time visible emissions is present has exceeded 1 minute, whichever time period is less. Alternatively, you may conduct visible emissions monitoring according to § 60.5417b(h). 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 of appendix A-7 to this part visual observation as described in this paragraph or be monitored according to § 60.5417b(h).

(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 methane and VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of § 60.5413b(b). As an alternative to the performance testing requirements of § 60.5413b(b), you may demonstrate initial compliance by conducting a design analysis for vapor recovery devices according to the requirements of § 60.5413b(c). For a condenser, you also must calculate the daily average condenser outlet temperature in accordance with § 60.5417b(e), and you must determine the condenser efficiency for the current operating day using the daily average condenser outlet temperature and the condenser performance curve established in accordance with § 60.5417b(f)(2). You must determine the average TOC emission reduction in accordance with § 60.5415b(f)(1)(ix)(D). For a carbon adsorption system, you also must comply with paragraph (c) of this section.

(3) Each flare must be designed and operated according to the requirements specified in paragraphs (a)(3)(i) through (viii) of this section, as applicable. Alternatively, flares must meet the requirements specified in paragraph (d) of this section.

(i) For unassisted flares, you must maintain the NHV of the vent gas sent to the flare at or above 200 Btu/scf.

(ii) For flares that use pressure-assisted burner tips to promote mixing at the burner tip, you must maintain the NHV of the vent gas sent to the flare at or above 800 Btu/scf.

(iii) For steam-assisted and air-assisted flares, you must maintain the NHV_{cz} at or above 270 Btu/scf.

(iv) For flares with perimeter assist air, you must maintain the NHV_{dil} at or above 22 Btu/sqft. If the only assist air provided to the flare is perimeter assist air intentionally entrained in lower and/or upper steam at the flare tip and the effective diameter is 9 inches or greater, you are not required to comply with the NHV_{dil} limit.

(v) For flares other than pressure-assisted flares, you must demonstrate compliance with the flare tip velocity limits in § 60.18(b) according to § 60.5417b(d)(8)(iv). The maximum flare tip velocity limits do not apply for pressure-assisted flares.

(vi) You must operate the flare at or above the minimum inlet gas flow rate. The minimum inlet gas flow rate is established based on manufacturer recommendations.

(vii) You must operate the flare with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period. You must conduct the compliance determination with the visible emission limits using Method 22 of appendix A-7 to this part, or you must monitor the flare according to § 60.5417b(h).

(viii) After January 22, 2027, you must install and operate a continuous burning pilot or combustion flame. After January 22, 2027, an alert must be sent to the nearest control room whenever the pilot or combustion flame is unlit.

(b) You must operate each control device installed on your well, centrifugal compressor, reciprocating compressor, storage vessel, process controller, pump, or process unit equipment 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 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.

(2) For each control device monitored in accordance with the requirements of § 60.5417b(a) through (i), you must demonstrate compliance according to the requirements of § 60.5415b(f), as applicable.

(c) For each carbon adsorption system used as a control device to meet the requirements of paragraph (a)(2) of this section, you must comply with the requirements of paragraph (c)(1) of this section. If the carbon adsorption system is a regenerative-type carbon adsorption system, you also must comply with the requirements of paragraph (c)(2) of this section.

(1) You must manage the carbon in accordance with the requirements specified in paragraphs (c)(1)(i) and (ii) of this section.

(i) Following the initial startup of the control device, you must replace all carbon in the carbon adsorption system with fresh carbon on a regular, predetermined time interval that is no longer than the carbon service life established according to § 60.5413b(c)(2) or (3). You must maintain records identifying the schedule for replacement and records of each carbon replacement as required in § 60.5420b(c)(11).

(ii) You must either regenerate, reactivate, or burn the spent carbon removed from the carbon adsorption system in one of the units specified in paragraphs (c)(1)(ii)(A) through (F) of this section.

(A) Regenerate or reactivate the spent carbon in a unit for which you have been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 264, subpart X.

(B) Regenerate or reactivate the spent carbon in a unit equipped with an operating organic air emissions control in accordance with an emissions standard for VOC under another subpart in 40 CFR part 63 or this part.

(C) Burn the spent carbon in a hazardous waste incinerator for which the owner or operator complies with the requirements of 40 CFR part 63, subpart EEE, and has submitted a Notification of Compliance under 40 CFR 63.1207(j).

(D) Burn the spent carbon in a hazardous waste boiler or industrial furnace for which the owner or operator complies with the requirements of 40 CFR part 63, subpart EEE, and has submitted a Notification of Compliance under 40 CFR 63.1207(j).

(E) Burn the spent carbon in an industrial furnace for which you have been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 266, subpart H.

(F) Burn the spent carbon in an industrial furnace that you have designed and operated in accordance with the interim status requirements of 40 CFR part 266, subpart H.

(2) You must comply with the requirements of paragraph (c)(2)(i) through (iii) of this section for each regenerative-type carbon adsorption system.

(i) You must measure and record the average total regeneration stream mass flow or volumetric flow during each carbon bed regeneration cycle to demonstrate compliance with the total regeneration stream flow established in accordance with § 60.5413b(c)(2).

(ii) You must check the mechanical connections for leakage at least every month, and you must perform a visual inspection at least every 3 months of all components of the flow continuous parameter monitoring system for physical and operational integrity and all electrical connections for oxidation and galvanic corrosion, if your continuous parameter monitoring system is not equipped with a redundant flow sensor.

(iii) You must measure and record the average carbon bed temperature for the duration of the carbon bed steaming cycle and measure the actual carbon bed temperature after regeneration and within 15 minutes of completing the cooling cycle. You must maintain the average carbon bed temperature above the temperature limit in established accordance with § 60.5413b(c)(2) during the carbon bed steaming cycle and below the carbon bed temperature established in accordance with § 60.5413b(c)(2) after the regeneration cycle.

(d) To demonstrate that a flare or enclosed combustion device reduces methane and VOC in the gases vented to the device by 95.0 percent by weight or greater, as outlined in § 60.8(b), you may submit a request for an alternative test method. At a minimum, the request must follow the requirements outlined in paragraphs (d)(1) through (5) of this section.

(1) The alternative method must be capable of demonstrating continuous compliance with a combustion efficiency of 95.0 percent or greater or it must be capable of demonstrating continuous compliance with the following metrics:

(i) NHV_{cz} of 270 Btu/scf or greater.

(ii) NHV_{dil} of 22 Btu/sqft or greater, if the alternative test method will be used for enclosed combustion devices or flares with perimeter assist air.

(2) The alternative method must be validated according to Method 301 in appendix A of 40 CFR part 63 for each type of control device covered by the alternative test method (*e.g.*, air-assisted flare, unassisted enclosed combustion device) or the alternative test method must contain performance-based procedures and indicators to ensure self-validation.

(3) At a minimum the alternative test method must provide a reading for each successive 15-minute period.

(4) The alternative test method must be capable of documenting periods when the enclosed combustion device or flare operates with visible emissions. If the alternative test method cannot identify periods of visible emissions, you must conduct the inspections required by § 60.5417b(d)(8)(v).

(5) If the alternative test method demonstrates compliance with the metrics specified in paragraphs (d)(1)(i) and (ii) of this section instead of demonstrating continuous compliance with 95.0 percent or greater combustion efficiency, after January 22, 2027, you must still install the pilot or combustion flame monitoring system

required by § 60.5417b(d)(8)(i). If the alternative test method demonstrates continuous compliance with a combustion efficiency of 95.0 percent or greater, the requirement in § 60.5417b(d)(8)(i) no longer applies.

§ 60.5413b What are the performance testing procedures for control devices?

This section applies to the performance testing of control devices used to demonstrate compliance with the emissions standards for your well, centrifugal compressor, reciprocating compressor, storage vessel, process controller, pump, or process unit equipment affected facilities. You must demonstrate that a control device achieves the performance requirements of § 60.5412b(a)(1) or (2) using the performance test methods and procedures specified in this section. For condensers and carbon adsorbers, 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 well, centrifugal compressor, reciprocating compressor, storage vessel, process controller, pump, or process unit equipment affected facilities.

(a) *Performance test exemptions.* You are exempt from the requirements to conduct initial and periodic performance tests and design analyses if you use any of the control devices described in paragraphs (a)(1) through (6) of this section. You are exempt from the requirements to conduct an initial performance test if you use a control device described in paragraph (a)(7) of this section.

(1) A flare that is designed and operated in accordance with the requirements in § 60.5412b(a)(3). You must conduct the compliance determination using Method 22 of appendix A-7 to this part to determine visible emissions or monitor the flare according to § 60.5417b(h). The net heating value of the vent gas must be determined according to § 60.5417b(d)(8)(ii).

(2) A boiler or process heater with a design heat input capacity of 44 megawatts or greater.

(3) A boiler or process heater into which the vent stream is introduced with the primary fuel or is used as the primary fuel.

(4) A boiler or process heater burning hazardous waste for which you have been issued a final permit under 40 CFR part 270 and comply with the requirements of 40 CFR part 266, subpart H; you have certified compliance with the interim status requirements of 40 CFR part 266, subpart H; you have submitted a Notification of Compliance under 40 CFR 63.1207(j) and comply with the requirements of 40 CFR part 63, subpart EEE; or you comply with 40 CFR part 63, subpart EEE and will submit a Notification of Compliance under 40 CFR 63.1207(j) by the date specified in § 60.5420b(b)(12) for submitting the initial performance test report.

(5) A hazardous waste incinerator for which you have submitted a Notification of Compliance under 40 CFR 63.1207(j), or for which you will submit a Notification of Compliance under 40 CFR 63.1207(j) by the date specified in § 60.5420b(b)(12) for submitting the initial performance test report, and you comply with the requirements of 40 CFR part 63, subpart EEE.

(6) A control device for which performance test is waived in accordance with § 60.8(b).

(7) A control device whose model can be demonstrated to meet the performance requirements of § 60.5412b(a)(1)(i) through a performance test conducted by the manufacturer, as specified in paragraph (d) of this section.

(b) *Test methods and procedures.* You must use the test methods and procedures specified in paragraphs (b)(1) through (4) of this section, as applicable, for each performance test conducted to demonstrate that a control device meets the requirements of § 60.5412b(a)(1) or (2). You must conduct the initial and periodic performance tests according to the schedule specified in paragraph (b)(5) of this section. Each performance test must consist of a minimum of 3 test runs. Each run must be at least 1 hour long.

- (1) You must use Method 1 or 1A of appendix A-1 to this part, as appropriate, to select the sampling sites. Any references to particulate mentioned in Methods 1 and 1A do not apply to this section.
- (i) Sampling sites must be located at the inlet of the first control device and at the outlet of the final control device to determine compliance with a control device percent reduction requirement.
- (ii) The sampling site must be located at the outlet of the combustion device to determine compliance with a TOC exhaust gas concentration limit.
- (2) You must determine the gas volumetric flow rate using Method 2, 2A, 2C, or 2D of appendix A-2 to this part, as appropriate.
- (3) To determine compliance with the control device percent reduction performance requirement in § 60.5412b(a)(1)(i) or (a)(2), you must use Method 25A of appendix A-7 to this part. You must use Method 4 of appendix A-3 to this part to convert the Method 25A results to a dry basis. You must use the procedures in paragraphs (b)(3)(i) through (iii) of this section to calculate percent reduction efficiency.
- (i) You must compute the mass rate of TOC using the following equations:

Equations 1 and 2 to paragraph (b)(3)(i)

$$E_i = K_2 C_i M_p Q_i$$

$$E_o = K_2 C_o M_p Q_o$$

Where:

E_i , E_o = Mass rate of TOC at the inlet and outlet of the control device, respectively, dry basis, kilograms per hour.

K_2 = Constant, 2.494×10^{-6} (parts per million) (gram-mole per standard cubic meter) (kilogram/gram) (minute/hour), where standard temperature (gram-mole per standard cubic meter) is 20 degrees Celsius.

C_i , C_o = Concentration of TOC, as propane, of the gas stream as measured by Method 25A of appendix A-7 to this part at the inlet and outlet of the control device, respectively, dry basis, parts per million by volume.

M_p = Molecular weight of propane, 44.1 gram/gram-mole.

Q_i , Q_o = Flow rate of gas stream at the inlet and outlet of the control device, respectively, dry standard cubic meter per minute.

- (ii) You must calculate the percent reduction in TOC as follows:

Equation 3 to paragraph (b)(3)(ii)

$$R_{cd} = \frac{E_i - E_o}{E_i} \times 100\%$$

Where:

R_{cd} = Control efficiency of control device, percent.

E_i = Mass rate of TOC at the inlet to the control device as calculated under paragraph (b)(3)(i) of this section, kilograms per hour.

E_o = Mass rate of TOC at the outlet of the control device, as calculated under paragraph (b)(3)(i) of this section, kilograms per hour.

(iii) If the vent stream entering a boiler or process heater with a design capacity less than 44 megawatts is introduced with the combustion air or as a secondary fuel, you must determine the weight-percent reduction of total TOC across the device by comparing the TOC in all combusted vent streams and primary and secondary fuels with the TOC exiting the device, respectively.

(4) You must use Method 25A of appendix A-7 to this part to measure TOC, as propane, to determine compliance with the TOC exhaust gas concentration limit specified in § 60.5412b(a)(1)(i). You must determine the concentration in parts per million by volume on a wet basis and correct it to 3 percent oxygen. You must use the emission rate correction factor for excess air, integrated sampling and analysis procedures of Method 3A or 3B of appendix A-2 to this part, ASTM D6522-20, or ANSI/ASME PTC 19.10-1981, Part 10 (manual portion only) (both incorporated by reference, see § 60.17) to determine the oxygen concentration. The samples must be taken during the same time that the samples are taken for determining TOC concentration. You must correct the TOC concentration for percent oxygen as follows:

Equation 4 to paragraph (b)(4)

$$C_c = C_m \left(\frac{17.9}{20.9 - \%O_{2m}} \right)$$

Where:

C_c = TOC concentration, as propane, corrected to 3 percent oxygen, parts per million by volume on a wet basis.

C_m = TOC concentration, as propane, parts per million by volume on a wet basis.

$\%O_{2m}$ = Concentration of oxygen, percent by volume as measured, wet.

(5) You must conduct performance tests according to the schedule specified in paragraphs (b)(5)(i) through (iii) of this section.

(i) You must conduct an initial performance test within 180 days after initial startup for your affected facility. You must submit the performance test results as required in § 60.5420b(b)(12).

(ii) You must conduct periodic performance tests for all control devices required to conduct initial performance tests. You must conduct the first periodic performance test no later than 60 months after the initial performance test required in paragraph (b)(5)(i) of this section. You must conduct subsequent periodic performance tests at intervals no longer than 60 months following the previous periodic performance test or whenever you desire to establish a new operating limit. If a control device is not operational at the time a performance test is due, you must conduct the performance test no later than 30 calendar days after returning the control device to service. You must submit the periodic performance test results as specified in § 60.5420b(b)(12).

(iii) If the initial performance test was conducted by the manufacturer under paragraph (d) of this section, you must conduct the first periodic performance test no later than 60 months after initial installation and startup of the control device. You must conduct subsequent periodic performance tests at intervals no longer than 60 months following the previous periodic performance test. If a control device is not operational at the time a performance test is due, you must conduct the performance test no later than 30 calendar days after returning the control device to service. You must submit the periodic performance test results as specified in § 60.5420b(b)(12).

(c) Control device design analysis to meet the requirements of § 60.5412b(a)(2).

(1) For a condenser, the design analysis must include an analysis of the vent stream composition, constituent concentrations, flow rate, relative humidity, and temperature and must establish the design outlet organic compound concentration level, design average temperature of the condenser exhaust vent stream and the design average temperatures of the coolant fluid at the condenser inlet and outlet.

(2) For a regenerable carbon adsorption system, the design analysis shall include the vent stream composition, constituent concentrations, flow rate, relative humidity and temperature and shall establish the design exhaust vent stream organic compound concentration level, adsorption cycle time, number and capacity of carbon beds, type and working capacity of activated carbon used for the carbon beds, design total regeneration stream flow over the period of each complete carbon bed regeneration cycle, design carbon bed temperature after regeneration, design carbon bed regeneration time and design service life of the carbon.

(3) For a nonregenerable carbon adsorption system, such as a carbon canister, the design analysis shall include the vent stream composition, constituent concentrations, flow rate, relative humidity and temperature and shall establish the design exhaust vent stream organic compound concentration level, capacity of the carbon bed, type and working capacity of activated carbon used for the carbon bed and design carbon replacement interval based on the total carbon working capacity of the control device and source operating schedule. In addition, these systems shall incorporate dual carbon canisters in case of emission breakthrough occurring in one canister.

(4) If you and the Administrator do not agree on a demonstration of control device performance using a design analysis, then you must perform a performance test in accordance with the requirements of paragraph (b) of this section to resolve the disagreement. The Administrator may choose to have an authorized representative observe the performance test.

(d) Performance testing for combustion control devices—manufacturers' performance test.

(1) This paragraph (d) 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 1-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- to 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- to 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- to 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) and (ii) of this section.

(i) The inlet gas flow metering system must be located in accordance with Method 2A of appendix A-1 of this part (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 to appendix A-1 of this part. 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) and (ii) of this section.

(i) At the inlet gas sampling location, securely connect a fused silica-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(R2010) (incorporated by reference, see § 60.17).

(B) Hydrogen (H₂), carbon monoxide (CO), carbon dioxide (CO₂), nitrogen (N₂), oxygen (O₂) using ASTM D1945-03(R2010) (incorporated by reference, see § 60.17).

(C) Higher heating value using ASTM D3588-98(R2003) or ASTM D4891-89(R2006) (both incorporated by reference, see § 60.17).

(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) and (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 of appendix A-1 to this part for determining flow measurement traverse point location, and Method 2 of appendix A-1 to this part 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 moisture test required by Method 4 of appendix A-3 to this part following the procedure specified in (d)(7)(i)(A) and (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) and (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 of appendix A-2 to this part must be modified 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 of appendix A-3 to this part. Traverse both ports with the sampling train required by Method 4 of appendix A-3 to this part during each test run. Ambient air must

not be introduced into the integrated bag sample required by Method 3C of appendix A-2 to this part during the port change.

(iii) Excess air must be determined using resultant data from the Method 3C tests and Method 3B of appendix A-2 to this part, equation 3B-1 in Method 3B, or ANSI/ASME PTC 19.10-1981, Part 10 (manual portion only) (incorporated by reference, see § 60.17).

(8) Carbon monoxide must be determined using Method 10 of appendix A-4 to this part. Run the test simultaneously with Method 25A of appendix A-7 to this part 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 of appendix A-7 to this part, 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 tests, each no less than 60 minutes in duration.

(iii) A 0 to 10 parts per million by volume-wet (ppmvw) (as propane) measurement range is preferred; as an alternative a 0 to 30 ppmvw (as propane) measurement range may be used.

(iv) Calibration gases must be propane in air and be certified through EPA-600/R-12/531—"EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards," (incorporated by reference, see § 60.17).

(v) THC measurements must be reported in terms of ppmvw as propane.

(vi) THC results must be corrected to 3 percent CO₂, as measured by Method 3C of appendix A-2 to this part. You must use the following equation for this diluent concentration correction:

Equation 5 to paragraph (d)(9)(vi)

$$C_{corr} = C_{meas} \left(\frac{3}{CO_{2meas}} \right)$$

Where:

C_{meas} = The measured concentration of the pollutant.

CO_{2meas} = The measured concentration of the CO₂ diluent.

3 = The corrected reference concentration of CO₂ 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 of appendix A-7 to this part. 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)

(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) Results from Method 22 of appendix A-7 to this part determined under paragraph (d)(10) of this section with no indication of visible emissions.

(B) Average results from Method 25A of appendix A-7 to this part determined under paragraph (d)(9) of this section equal to or less than 10.0 ppmvw THC as propane corrected to 3.0 percent CO₂.

(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 CO₂.

(D) Excess air determined under paragraph (d)(7) of this section equal to or greater than 150 percent.

(ii) The manufacturer must determine a minimum inlet gas flow rate above which each control device model must be operated to achieve the criteria in paragraph (d)(11)(iii) of this section. 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 minimum and maximum inlet gas flow rate must be included in the test report required by paragraph (d)(12) of this section.

(iii) A manufacturer must demonstrate a destruction efficiency of at least 95.0 percent for THC, as propane. A control device model that demonstrates a destruction efficiency of 95.0 percent for THC, as propane, will meet the control requirement for 95.0 percent destruction of VOC and methane required under this subpart.

(12) The owner or operator of a combustion control device model tested under this paragraph (d)(12) must submit the information listed in paragraphs (d)(12)(i) through (vi) of this section for each test run in the test report required by this section in accordance with § 60.5420b(b)(13). Owners or operators who claim that any of the performance test information being submitted is confidential business information (CBI) must submit a complete file including information claimed to be CBI to the OAQPS CBI office. The preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol, or other online file sharing services. Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address oaqpscbi@epa.gov and should include clear CBI markings and be flagged to the attention of the Leader, Measurement Policy Group. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if you do not have your own file sharing service, please email oaqpscbi@epa.gov to request a file transfer link. If you cannot transmit the file electronically, you may send CBI information through the postal service to the following address: U.S. EPA, Attn: OAQPS Document Control Officer and Measurement Policy Group Leader, Mail Drop: C404-02, 109 T.W. Alexander Drive, P.O. Box 12055, RTP, North Carolina 27711. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope. The same file with the CBI omitted must be submitted to Oil_and_Gas_PT@EPA.GOV.

(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 minimum and 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 air range.
- (G) Flame arrestor(s).
- (H) Burner manifold.
- (I) Continuous 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) *Initial and continuous compliance for combustion control devices tested by the manufacturer in accordance with paragraph (d) of this section.* This paragraph (e) 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 criteria in paragraph (d)(11) of this section by installing a device tested under paragraph (d) of this section, complying with the criteria specified in paragraphs (e)(1) through (10) of this section, maintaining the records specified in § 60.5420b(c)(11) and submitting the report specified in § 60.5420b(b)(11)(v) and (13).

- (1) The inlet gas flow rate must be equal to or greater than the minimum inlet gas flow rate and equal to or less than the maximum inlet gas flow rate specified by the manufacturer.
- (2) After January 22, 2027, a pilot or combustion flame must be present at all times of operation. After January 22, 2027, an alert must be sent to the nearest control room whenever the pilot or combustion flame is unlit.
- (3) Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period. A visible emissions test conducted according to section 11 of Method 22 of appendix A-7 to this part 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 or once the amount of time visible emissions is present has exceeded 1 minute, whichever time period is less. Alternatively, you may conduct visible emissions monitoring according to § 60.5417b(h).

(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 a visual observation according to Method 22 of appendix A-7 to this part as described in paragraph (e)(3) of this section or be monitored according to § 60.5417b(h).

(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 website: <https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry>.

(7) Ensure that each enclosed combustion device is maintained in a leak free condition.

(8) Operate each control device following the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices for minimizing emissions.

(9) Install and operate the continuous parameter monitoring systems in accordance with § 60.5417b(a) and (c) through (i).

(10) Comply with the applicable NHV limit specified in § 60.5412b(a)(1)(iv).

§ 60.5415b How do I demonstrate continuous compliance with the standards for each of my affected facilities?

(a) *Well completion standards for well affected facility.* For each well completion operation at your well affected facility, you must demonstrate continuous compliance with the requirements of § 60.5375b by submitting the annual report required by § 60.5420b(b)(1) and (2) and maintaining the records for each completion operation specified in § 60.5420b(c)(1).

(b) *Gas well liquids unloading standards for well affected facility.* For each well liquids unloading operation at your well affected facility, you must demonstrate continuous compliance with the requirements of § 60.5376b by submitting the annual report information specified in § 60.5420b(b)(1) and (3) and maintaining the records for each well liquids unloading event specified in § 60.5420b(c)(2). For each gas well liquids unloading well affected facility that complies with the requirements of § 60.5376b(g), you must route emissions to a control device through a closed vent system and continuously comply with the closed vent requirements of § 60.5416b. You also must comply with the requirements specified in paragraph (f) of this section and maintain the records in § 60.5420b(c)(8), (10) and (12).

(c) *Associated gas well standards for well affected facility.* For each associated gas well, you must demonstrate continuous compliance with the requirements of § 60.5377b by submitting the reports required by § 60.5420b(b)(1) and (4) and maintaining the records specified in § 60.5420b(c)(3). For each associated gas well that complies with the requirements of § 60.5377b(d) or (f), you must route emissions to a control device through a closed vent system and continuously comply with the closed vent requirements of § 60.5416b. You also must comply with the requirements specified in paragraph (f) of this section and maintain the records in § 60.5420b(c)(8), (10) and (12).

(d) *Centrifugal compressor affected facility.* For each wet seal centrifugal compressor affected facility complying with § 60.5380b(a)(1) and (2), or with § 60.5380b(a)(3) by routing emissions to a control device or to a process, you must demonstrate continuous compliance according to paragraph (d)(1) and paragraphs (d)(3) and (4) of this section. For each self-contained wet seal centrifugal compressor complying with the requirements in § 60.5380b(a)(4), you must demonstrate continuous compliance according to paragraphs (d)(2) through (4) of this section. For each centrifugal compressor on the Alaska North Slope equipped with sour seal oil separator and

capture system, complying with the requirements of § 60.5380b(a)(5), you must demonstrate continuous compliance according to paragraphs (d)(2) through (4) of this section. For each dry seal centrifugal compressor complying with the requirements in § 60.5380b(a)(6), you must demonstrate continuous compliance according to paragraphs (d)(2) through (4) of this section.

(1) For each wet seal centrifugal compressor affected facility complying by routing emissions to a control device or to a process, you must operate the wet seal emissions collection system to route emissions to a control device or a process through a closed vent system and continuously comply with the cover and closed vent requirements of § 60.5416b. If you comply with § 60.5380b(a)(2) by using a control device, you also must comply with the requirements in paragraph (f) of this section.

(2) You must maintain volumetric flow rate at or below the flow rates specified in § 60.5380b(a)(4) for your self-contained centrifugal compressor, § 60.5380b(a)(5) for your Alaska North Slope centrifugal compressor equipped with a sour seal oil separator and capture system, and § 60.5380b(a)(6) for your centrifugal compressor equipped with dry seals, as applicable. You must conduct the required volumetric flow rate measurement of your self-contained wet seal centrifugal compressor in accordance with § 60.5380b(a)(4), your Alaska North Slope centrifugal compressor equipped with a sour seal oil separator and capture system in accordance with § 60.5380b(a)(5), and your dry seal centrifugal compressor in accordance with § 60.5380b(a)(6), as applicable, on or before 8,760 hours of operation after your last volumetric flow rate measurement which demonstrates compliance with the volumetric flow rate specified in § 60.5380b(a)(4) for your self-contained centrifugal compressor, § 60.5380b(a)(5) for your Alaska North Slope centrifugal compressor equipped with a sour seal oil separator and capture system and § 60.5380b(a)(6) for your centrifugal compressor equipped with dry seals, as applicable.

(3) You must submit the annual reports as required in § 60.5420b(b)(1), (5), and (11)(i) through (iv), as applicable.

(4) You must maintain records as required in § 60.5420b(c)(4), (8) through (10), and (12), as applicable.

(e) *Pump affected facility.* To demonstrate continuous compliance with the GHG and VOC standards for your pump affected facility as required by § 60.5393b, you must comply with paragraphs (e)(1) through (3) of this section.

(1) For pump affected facilities complying with the requirements of § 60.5393b(a) by routing emissions to a process, and for pump affected facilities complying with the requirements of § 60.5393b(b)(2), or (3), you must route emissions through a closed vent system and continuously comply with the closed vent requirements of § 60.5416b. If you comply with § 60.5393b(b)(3), you also must comply with the requirements in paragraph (f) of this section.

(2) You must submit the annual reports for your pump affected facility as required in § 60.5420b(b)(1), (10), and (11)(i) through (iv), as applicable.

(3) You must maintain the records for your pump affected facility as specified in § 60.5420b(c)(8), (10) through (12), and (15), as applicable.

(f) *Additional continuous compliance requirements for well, centrifugal compressor, reciprocating compressor, process controllers in Alaska, storage vessel, process unit equipment, or pump affected facilities.* For each associated gas well, each gas well that conducts liquids unloading, each centrifugal compressor affected facility, each reciprocating compressor affected facility, each process controller affected facility in Alaska, each storage vessel affected facility, each process unit equipment affected facility, and each pump affected facility referenced to this paragraph from either paragraph (b), (c), (d)(1), (e)(1), (g)(2), (h)(2), (i)(5)(ii)(B), or (j)(12) of this section, you must also install monitoring systems as specified in § 60.5417b, demonstrate continuous compliance according to paragraph (f)(1) of this section, maintain the records in paragraph (f)(2) of this section, and comply with the reporting requirements specified in paragraph (f)(3) of this section.

(1) You must demonstrate continuous compliance with the control device performance requirements of § 60.5412b(a) using the procedures specified in paragraphs (f)(1)(i) through (viii) of this section and conducting the monitoring as required by § 60.5417b. If you use a condenser as the control device to achieve the requirements specified in § 60.5412b(a)(2), you may demonstrate compliance according to paragraph (f)(1)(ix) of this section. You may switch between compliance with paragraphs (f)(1)(i) through (viii) of this section and compliance with paragraph (f)(1)(ix) 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, following the change. If you use an enclosed combustion device or a flare as the control device, you must also conduct the monitoring required in paragraph (f)(1)(x) of this section. If you use an enclosed combustion device or flare using an alternative test method approved under § 60.5412b(d), you must use the procedures in paragraph (f)(1)(xi) of this section in lieu of the procedures in paragraphs (f)(1)(i) through (viii) of this section, but you must still conduct the monitoring required in paragraph (f)(1)(x) of this section.

(i) You must operate below (or above) the site-specific maximum (or minimum) parameter value established according to the requirements of § 60.5417b(f)(1). For flares, you must operate above the limits specified in paragraphs (f)(1)(vii)(B) of this section.

(ii) You must calculate the average of the applicable monitored parameter in accordance with § 60.5417b(e).

(iii) Compliance with the operating parameter limit is achieved when the average of the monitoring parameter value calculated under paragraph (f)(1)(ii) of this section is either equal to or greater than the minimum parameter value or equal to or less than the maximum parameter value established under paragraph (f)(1)(i) of this section. When performance testing of a combustion control device is conducted by the device manufacturer as specified in § 60.5413b(d), compliance with the operating parameter limit is achieved when the criteria in § 60.5413b(e) are met.

(iv) You must operate the continuous monitoring system required in § 60.5417b(a) 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.

(vii) If you use an enclosed combustion device to meet the requirements of § 60.5412b(a)(1) and you demonstrate compliance using the test procedures specified in § 60.5413b(b), or you use a flare designed and operated in accordance with § 60.5412b(a)(3), you must comply with the applicable requirements in paragraphs (f)(1)(vii)(A) through (E) of this section.

(A) For each enclosed combustion device which is not a catalytic vapor incinerator and for each flare, you must comply with the requirements in paragraphs (f)(1)(vii)(A)(1) through (4) of this section.

(1) After January 22, 2027, a pilot or combustion flame must be present at all times of operation. After January 22, 2027, an alert must be sent to the nearest control room whenever the pilot or combustion flame is unlit.

(2) Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period. A visible emissions test conducted according to section 11 of Method 22 of appendix A-7 to this part, 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 or once the amount of time visible emissions is present has exceeded 1 minute, whichever time period is less. Alternatively, you may conduct visible emissions monitoring according to § 60.5417b(h).

(3) 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.

(4) Following return to operation from maintenance or repair activity, each device must pass a Method 22 of appendix A-7 to this part visual observation as described in paragraph (f)(1)(vii)(A)(2) of this section or be monitored according to § 60.5417b(h).

(B) For flares, you must comply with the requirements in paragraphs (f)(1)(vii)(B)(1) through (6) of this section.

(1) For unassisted flares, maintain the NHV of the gas sent to the flare at or above 200 Btu/scf.

(2) If you use a pressure assisted flare, maintain the NHV of gas sent to the flare at or above 800 Btu/scf.

(3) For steam-assisted and air-assisted flares, maintain the NHV_{cz} at or above 270 Btu/scf.

(4) For flares with perimeter assist air, maintain the NHV_{dii} at or above 22 Btu/sqft. If the only assist air provided to the flare is perimeter assist air intentionally entrained in lower and/or upper steam at the flare tip and the effective diameter is 9 inches or greater, you are not required to comply with the NHV_{dii} limit.

(5) Unless you use a pressure-assisted flare, maintain the flare tip velocity below the applicable limits in § 60.18(b).

(6) Maintain the total gas flow to the flare above the minimum inlet gas flow rate. The minimum inlet gas flow rate is established based on manufacturer recommendations.

(C) For enclosed combustion devices for which, during the performance test conducted under § 60.5413b(b), the combustion zone temperature is not an indicator of destruction efficiency, you must comply with the requirements in paragraphs (f)(1)(vii)(C)(1) through (5) of this section, as applicable.

(1) Maintain the total gas flow to the enclosed combustion device at or above the minimum inlet gas flow rate and at or below the maximum inlet flow rate for the enclosed combustion device established in accordance with § 60.5417b(f).

(2) For unassisted enclosed combustion devices, maintain the NHV of the gas sent to the enclosed combustion device at or above 200 Btu/scf.

(3) For enclosed combustion devices that use pressure-assisted burner tips to promote mixing at the burner tip, maintain the NHV of the gas sent to the enclosed combustion device at or above 800 Btu/scf.

(4) For steam-assisted and air-assisted enclosed combustion devices, maintain the NHV_{cz} at or above 270 Btu/scf.

(5) For enclosed combustion devices with perimeter assist air, maintain the NHV_{dil} at or above 22 Btu/sqft. If the only assist air provided to the enclosed combustion device is perimeter assist air intentionally entrained in lower and/or upper steam at the flare tip and the effective diameter is 9 inches or greater, you are not required to comply with the NHV_{dil} limit.

(D) For enclosed combustion devices for which, during the performance test conducted under § 60.5413b(b), the combustion zone temperature is demonstrated to be an indicator of destruction efficiency, you must comply with the requirements in paragraphs (f)(1)(vii)(D)(1) and (2) of this section.

(1) Maintain the temperature at or above the minimum temperature established during the most recent performance test. The minimum temperature limit established during the most recent performance test is the average temperature recorded during each test run, averaged across the 3 test runs (average of the test run averages).

(2) Maintain the total gas flow to the enclosed combustion device at or above the minimum inlet gas flow rate and at or below the maximum inlet flow rate for the enclosed combustion device established in accordance with § 60.5417b(f).

(E) For catalytic vapor incinerators you must operate the catalytic vapor incinerator at or above the minimum temperature of the catalyst bed inlet and at or above the minimum temperature differential between the catalyst bed inlet and the catalyst bed outlet established in accordance with § 60.5417b(f).

(viii) If you use a carbon adsorption system as the control device to meet the requirements of § 60.5412b(a)(2), you must demonstrate compliance by the procedures in paragraphs (f)(1)(viii)(A) and (B) of this section, as applicable.

(A) If you use a regenerative-type carbon adsorption system, you must comply with paragraphs (f)(1)(viii)(A)(1) through (4) of this section.

(1) You must maintain the average regenerative mass flow or volumetric flow to the carbon adsorber during each bed regeneration cycle above the limit established in accordance with § 60.5413b(c)(2).

(2) You must maintain the average carbon bed temperature above the temperature limit established in accordance with § 60.5413b(c)(2) during the carbon bed steaming cycle and below the carbon bed temperature established in accordance with § 60.5413b(c)(2) after the regeneration cycle.

(3) You must check the mechanical connections for leakage at least every month, and you must perform a visual inspection at least every 3 months of all components of the continuous parameter monitoring system for physical and operational integrity and all electrical connections for oxidation and galvanic corrosion if your continuous parameter monitoring system is not equipped with a redundant flow sensor.

(4) You must replace all carbon in the carbon adsorption system with fresh carbon on a regular, predetermined time interval that is no longer than the carbon service life established according to § 60.5413b(c)(2).

(B) If you use a nonregenerative-type carbon adsorption system, 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 § 60.5413b(c)(3).

(ix) If you use a condenser as the control device to achieve the percent reduction performance requirements specified in § 60.5412b(a)(2), you must demonstrate compliance using the procedures in paragraphs (f)(1)(ix)(A) through (E) of this section.

(A) You must establish a site-specific condenser performance curve according to § 60.5417b(f)(2).

(B) You must calculate the daily average condenser outlet temperature in accordance with § 60.5417b(e).

(C) You must determine the condenser efficiency for the current operating day using the daily average condenser outlet temperature calculated under paragraph (f)(1)(ix)(B) of this section and the condenser performance curve established under paragraph (f)(1)(ix)(A) of this section.

(D) Except as provided in paragraphs (f)(1)(ix)(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 (f)(1)(ix)(C) of this section.

(1) After the compliance dates specified in § 60.5370b(a), 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 date. 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 § 60.5370b(a), 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 (f)(1)(ix)(D) of this section is equal to or greater than 95.0 percent.

(x) During each inspection conducted using an OGI camera under § 60.5397b and during each periodic screening event or each inspection conducted using an OGI camera under § 60.5398b, you must observe each enclosed combustion device and flare to determine if it is operating properly. You must determine

whether there is a flame present and whether any uncontrolled emissions from the control device are visible with the OGI camera or the technique used to conduct the periodic screening event. During each inspection conducted under § 60.5397b using AVO, you must observe each enclosed combustion device and flare to determine if it is operating properly. Visually confirm that the pilot or combustion flame is lit and that the pilot or combustion flame is operating properly.

(xi) If you use an enclosed combustion device or flare using an alternative test method approved under § 60.5412b(d), you must comply with paragraphs (f)(1)(xi)(A) through (E) of this section.

(A) You must maintain the combustion efficiency at or above 95.0 percent. Alternatively, if the alternative test method does not directly monitor combustion efficiency, you must comply with the applicable requirements in paragraphs (f)(1)(xi)(A)(1) and (2) of this section.

(1) Maintain the NHV_{cz} at or above 270 Btu/scf.

(2) For flares or enclosed combustion devices with perimeter assist air, maintain the NHV_{dil} at or above 22 Btu/sqft. If the only assist air provided to the flare or enclosed combustion device is perimeter assist air intentionally entrained in lower and/or upper steam at the flare tip and the effective diameter is 9 inches or greater, you are only required to comply with the NHV_{cz} limit specified in paragraph (f)(1)(xi)(A)(1) of this section.

(B) You must calculate the value of the applicable monitored metric(s) in accordance with the approved alternative test method. Compliance with the limit is achieved when the calculated values are within the range specified in paragraph (f)(1)(xi)(A) of this section.

(C) You must conduct monitoring using the alternative test method 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.

(D) 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 values to demonstrate compliance with the limits specified in paragraph (f)(1)(xi)(A) of this section. 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.

(E) Failure to collect required data is a deviation of the monitoring requirements.

(2) You must maintain the records as specified in § 60.5420b(c)(11) and (13).

(3) You must comply with the reporting requirements in § 60.5420b(b)(11) through (13).ecified in § 60.5420b(c)(11) and (13).

(3) You must comply with the reporting requirements in § 60.5420b(b)(11) through (13).

(g) *Reciprocating compressor affected facility.* For each reciprocating compressor affected facility complying with § 60.5385b(a) through (c), you must demonstrate continuous compliance according to paragraphs (g)(1), (5), and (6)

of this section. For each reciprocating compressor affected facility complying with § 60.5385b(d)(1) or (2), you must demonstrate continuous compliance according to paragraphs (g)(2), (5) and (6) of this section. For each reciprocating compressor affected facility complying with § 60.5385b(d)(3), you must demonstrate continuous compliance according to paragraphs (g)(3) through (6) of this section.

(1) You must maintain the volumetric flow rate at or below 2 scfm per cylinder (or at or below the combined volumetric flow rate determined by multiplying the number of cylinders by 2 scfm), and you must conduct the required volumetric flow rate measurement of your reciprocating compressor rod packing vents in accordance with § 60.5385b(b) on or before 8,760 hours of operation after your last volumetric flow rate measurement which demonstrated compliance with the applicable volumetric flow rate.

(2) You must operate the rod packing emissions collection system to route emissions to a control device or to a process through a closed vent system and continuously comply with the cover and closed vent requirements of § 60.5416b. If you comply with § 60.5385b(d) by using a control device, you also must comply with the requirements in paragraph (f) of this section.

(3) You must continuously monitor the number of hours of operation for each reciprocating compressor affected facility since initial startup, since May 7, 2024, since the previous flow rate measurement, or since the date of the most recent reciprocating compressor rod packing replacement, whichever date is latest.

(4) You must replace the reciprocating compressor rod packing on or before the total number of hours of operation reaches 8,760 hours.

(5) You must submit the annual reports as required in § 60.5420b(b)(1), (6), and (11)(i) through (iv), as applicable.

(6) You must maintain records as required in § 60.5420b(c)(5), (8) through (10), and (12), as applicable.

(h) *Process controller affected facility.* To demonstrate continuous compliance with GHG and VOC emission standards for your process controller affected facility as required by § 60.5390b, you must comply with paragraphs (h)(1) through (4) of this section, as applicable.

(1) Beginning January 22, 2027, or upon startup, whichever is later, you must demonstrate that your process controller affected facility does not emit any VOC or methane to the atmosphere by meeting the requirements of paragraph (h)(1)(i) or (ii) of this section.

(i) If you comply by routing the emissions to a process, you must route emissions through a closed vent system and continuously comply with the closed vent system inspection and monitoring requirements of § 60.5416b.

(ii) If you comply by using a self-contained natural gas-driven process controller, you must conduct the no identifiable emissions inspections required by § 60.5416b(b).

(2) For each process controller affected facility located at a site in Alaska that does not have access to electrical power and that complies by reducing methane and VOC emissions from all controllers in the process controller affected facility by 95.0 percent in accordance with § 60.5390b(b)(3), you must route emissions to a control device through a closed vent system and continuously comply with the closed vent requirements of § 60.5416b and the requirements in paragraph (f) of this section for the control device.

(3) You must submit the annual report for your process controller as required in § 60.5420b(b)(1), (7), and (11) through (13), as applicable.

(4) You must maintain the records as specified in § 60.5420b(c)(6), (8), (10), and (12) for each process controller affected facility, as applicable.

(i) *Storage vessel affected facility.* For each storage vessel affected facility, you must demonstrate continuous compliance with the requirements of § 60.5395b according to paragraphs (i)(1) through (10) of this section, as applicable.

(1) For each storage vessel affected facility complying with the requirements of § 60.5395b(a)(2), you must demonstrate continuous compliance according to paragraphs (i)(5), (9) and (10) of this section.

(2) For each storage vessel affected facility complying with the requirements of § 60.5395b(a)(3), you must demonstrate continuous compliance according to paragraphs (i)(2)(i), (ii), or (iii) of this section, as applicable, and (i)(9) and (10) of this section.

(i) You must maintain the uncontrolled actual VOC emissions at less than 4 tpy and the uncontrolled actual methane emissions at less than 14 tpy from the storage vessel affected facility.

(ii) You must comply with paragraph (i)(5) of this section as soon as liquids from the well are routed to the storage vessel affected facility following fracturing or refracturing according to the requirements of § 60.5395b(a)(3)(i).

(iii) You must comply with paragraph (i)(5) of this section within 30 days of the monthly determination according to the requirements of § 60.5395b(a)(3)(ii), where the monthly emissions determination indicates that VOC emissions from your storage vessel affected facility increase to 4 tpy or greater or methane emissions from your storage vessel affected facility increase to 14 tpy or greater and the increase is not associated with fracturing or refracturing of a well feeding the storage vessel affected facility.

(3) For each storage vessel affected facility or portion of a storage vessel affected facility removed from service, you must demonstrate compliance with the requirements of § 60.5395b(c)(1) or (2) by complying with paragraphs (i)(6), (7), (9), and (10) of this section.

(4) For each storage vessel affected facility or portion of a storage vessel affected facility returned to service, you must demonstrate compliance with the requirements of § 60.5395b(c)(3) and (4) by complying with paragraphs (i)(8) through (10) of this section.

(5) For each storage vessel affected facility, you must comply with paragraphs (i)(5)(i) and (ii) of this section.

(i) You must reduce VOC emissions as specified in § 60.5395b(a)(2).

(ii) For each control device installed to meet the requirements of § 60.5395b(a)(2), you must demonstrate continuous compliance with the performance requirements of § 60.5412b for each storage vessel affected facility using the procedure specified in paragraphs (i)(5)(ii)(A) and (i)(5)(ii)(B) of this section. When routing emissions to a process, you must demonstrate continuous compliance as specified in paragraph (i)(5)(ii)(A) of this section.

(A) You must comply with § 60.5416b for each cover and closed vent system.

(B) You must comply with the requirements specified in paragraph (f) of this section.

(6) You must completely empty and degas each storage vessel, such that each storage vessel no longer contains crude oil, condensate, produced water or intermediate hydrocarbon liquids. For a portion of a storage vessel affected facility to be removed from service, you must completely empty and degas the storage vessel(s), such that the storage vessel(s) no longer contains crude oil, condensate, produced water, or intermediate hydrocarbon liquids. A storage vessel where liquid is left on walls, as bottom clingage, or in pools due to floor irregularity is considered to be completely empty.

(7) You must disconnect the storage vessel(s) from the tank battery by isolating the storage vessel(s) from the tank battery such that the storage vessel(s) is no longer manifolded to the tank battery by liquid or vapor transfer.

(8) You must determine the affected facility status of a storage vessel returned to service as provided in § 60.5365b(e)(6).

(9) You must submit the annual reports as required by § 60.5420b(b)(1), (8), and (11)(i) through (iv).

(10) You must maintain the records as required by § 60.5420b(c)(7) through (10) and (c)(12), as applicable.

(j) *Process unit equipment affected facility.* For each process unit equipment affected facility, you must demonstrate continuous compliance with the requirements of § 60.5400b according to paragraphs (j)(1) through (4) and (11) through (15) of this section, unless you meet and comply with the exception in § 60.5402b(b), (e), or (f) or meet the exemption in § 60.5402b(c). Alternatively, if you comply with the GHG and VOC standards for process unit affected facilities using the standards in § 60.5401b, you must comply with paragraphs (j)(5) through (15) of this section, unless you meet the exemption in § 60.5402b(b) or (c) or the exception in § 60.5402b(e) and (f).

(1) You must conduct monitoring for each pump in light liquid service, pressure relief device in gas/vapor service, valve in gas/vapor and light liquid service and connector in gas/vapor and light liquid service as required by § 60.5400b(b).

(2) You must conduct monitoring as required by § 60.5400b(c) for each pump in light liquid service.

(3) You must conduct monitoring as required by § 60.5400b(d) for each pressure relief device in gas/vapor service.

(4) You must comply with the equipment requirements for each open-ended valve or line as required by § 60.5400b(e).

(5) You must conduct monitoring for each pump in light liquid service as required by § 60.5401b(b).

(6) You must conduct monitoring for each pressure relief device in gas/vapor service as required by § 60.5401b(c).

(7) You must comply with the equipment requirements for each open-ended valve or line as required by § 60.5401b(d).

(8) You must conduct monitoring for each valve in gas/vapor or light liquid service as required by § 60.5401b(f).

(9) You must conduct monitoring for each pump, valve, and connector in heavy liquid service and each pressure relief device in light liquid or heavy liquid service as required by § 60.5401b(g).

(10) You must conduct monitoring for each connector in gas/vapor or light liquid service as required by § 60.5401b(h).

(11) You must collect emissions and meet the closed vent system requirements as required by § 60.5416b for each pump equipped with a dual mechanical seal system that degasses the barrier fluid reservoir to a process or a control device, each pump which captures and transports leakage from the seal or seals to a process or control device, or each pressure relief device which captures and transports leakage through the pressure relief device to a process or control device.

(12) You comply with the requirements specified in paragraph (f) of this section.

(13) You must tag and repair each identified leak as required in § 60.5400(h) or § 60.5401b(i), as applicable.

(14) You must submit semiannual reports as required by § 60.5422b and the annual reports in § 60.5420b(b)(11)(i) through (iv), as applicable.

(15) You must maintain the records specified by § 60.5420b(c)(8), (c)(10), and (c)(12) as applicable and § 60.5421b.

(k) *Sweetening unit affected facility.* For each sweetening unit affected facility, you must demonstrate continuous compliance with the requirements of § 60.5405b(b) according to paragraphs (k)(1) through (10) of this section.

(1) You must determine the minimum required continuous reduction efficiency of SO₂ emissions (Z_c) as required by § 60.5406b(b).

(2) You must determine the emission reduction efficiency (R) achieved by your sulfur reduction technology using the procedures in § 60.5406b(c)(1) through (c)(4).

(3) You must demonstrate compliance with the standard at § 60.5405b(b) by comparing the minimum required sulfur dioxide emission reduction efficiency (Z_c) to the emission reduction efficiency achieved by the sulfur recovery technology (R), where R must be greater than or equal to Z_c .

(4) You must calibrate, maintain, and operate monitoring devices or perform measurements to determine the accumulation of sulfur product, the H₂S concentration, the average acid gas flow rate, and the sulfur feed rate in accordance with § 60.5407b(a).

(5) You must determine the required SO₂ emissions reduction efficiency each 24-hour period in accordance with § 60.5407b(a), § 60.5407b(d), and § 60.5407b(e), as applicable.

(6) You must calibrate, maintain, and operate monitoring devices and continuous emission monitors in accordance with § 60.5407b(b), (f), and (g), if you use an oxidation control system or a reduction control system followed by an incineration device.

(7) You must continuously operate the incineration device, if you use an oxidation control system or a reduction control system followed by an incineration device.

(8) You must calibrate, maintain, and operate a continuous monitoring system to measure the emission rate of reduced sulfur compounds in accordance with § 60.5407b(c), (f), and (g), if you use a reduction control system not followed by an incineration device.

(9) You must submit the reports as required by § 60.5423b(d).

(10) You must maintain the records as required by § 60.5423b(a), (e), and (f), as applicable.

(l) *Continuous compliance.* For each fugitive emissions components affected facility, you must demonstrate continuous compliance with the requirements of § 60.5397b(a) according to paragraphs (l)(1) through (4) of this section.

(1) *Monitoring.* You must conduct periodic monitoring surveys as required in § 60.5397b(e) and (g).

(2) *Repairs.* You must repair each identified source of fugitive emissions as required in § 60.5397b(h).

(3) *Reports.* You must submit annual reports for fugitive emissions components affected facilities as required in § 60.5420b(b)(1) and (9).

(4) *Records.* You must maintain records as specified in § 60.5420b(c)(14).

§ 60.5416b What are the initial and continuous cover and closed vent system inspection and monitoring requirements?

For each closed vent system and cover at your well, centrifugal compressor, reciprocating compressor, process controller, pump, storage vessel, and process unit equipment affected facilities, you must comply with the applicable requirements of paragraphs (a) and (b) of this section. Each self-contained natural gas process controller must comply with paragraph (b) of this section.

(a) *Inspections for closed vent systems, covers, and bypass devices.* 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 (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, except as provided in paragraphs (b)(7) and (8) of this section.

(1) For each closed vent system joint, seam, or other connection that is permanently or semi-permanently sealed (*e.g.*, a welded joint between two sections of hard piping or a bolted and gasketed ducting flange), you must meet the requirements specified in paragraphs (a)(1)(i) through (iii) of this section.

(i) Within the first 30 calendar days after January 22, 2027, or upon startup of the affected facility routing emissions through the closed vent system, whichever is later, conduct an initial inspection according to the test methods and procedures specified in paragraph (b) of this section to demonstrate that the closed vent system operates with no identifiable emissions.

(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. Beginning on the first annual inspection after January 22, 2027, and for all annual inspections thereafter, 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 identifiable emissions following any time the component is repaired or replaced or the connection is unsealed.

(iii) Conduct AVO inspections in accordance with and at the same frequency as specified for fugitive emissions components affected facilities located at the same type of site as specified in § 60.5397b(g). Process unit equipment affected facilities must conduct annual AVO inspections concurrent with the inspections required by paragraph (a)(1)(ii) of this section.

(2) For closed vent system components other than those specified in paragraph (a)(1) of this section, you must meet the requirements of paragraphs (a)(2)(i) through (iv) of this section.

(i) Conduct an initial inspection according to the test methods and procedures specified in paragraph (b) of this section within the first 30 calendar days after startup of the affected facility routing emissions through the closed vent system to demonstrate that the closed vent system or January 22, 2027, whichever is later, operates with no identifiable emissions.

(ii) Beginning January 22, 2027, conduct inspections according to the test methods, procedures, and frequencies specified in paragraph (b) of this section to demonstrate that the components or connections operate with no identifiable emissions.

(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. Beginning January 22, 2027, 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 identifiable emissions following any time the component is repaired or replaced or the connection is unsealed.

(iv) Conduct AVO inspections in accordance with and at the same frequency as specified for fugitive emissions components affected facilities located at the same type of site, as specified in § 60.5397b(g). Process unit equipment affected facilities must conduct annual AVO inspections concurrent with the inspections required by paragraph (a)(2)(iii) of this section.

(3) For each cover, you must meet the requirements of paragraphs (a)(3)(i) through (iv) of this section.

(i) Beginning January 22, 2027, conduct the inspections specified in paragraphs (a)(3)(ii) through (iv) of this section to identify defects that could result in air emissions and to ensure the cover operates with no identifiable emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in the cover, or between the cover and the separator wall; broken, cracked, or otherwise damaged seals or gaskets on closure devices; and broken or missing hatches, access covers, caps, or other closure devices. In the case where the storage vessel is buried partially or entirely underground, you must inspect only those portions of the cover that extend to or above the ground surface, and those connections that are on such portions of the cover (*e.g.*, fill ports, access hatches, gauge wells, etc.) and can be opened to the atmosphere.

(ii) An initial inspection according to the test methods and procedures specified in paragraph (b) of this section, following installation of the cover to demonstrate that each cover operates with no identifiable emissions.

(iii) Conduct AVO inspections in accordance with and at the same frequency as specified for fugitive emissions components affected facilities located at the same type of site as specified in § 60.5397b(g). Process unit equipment affected facilities must conduct annual AVO inspections concurrent with the inspections required by paragraph (a)(1)(ii) of this section.

(iv) Inspections according to the test methods, procedures, and schedules specified in paragraph (b) of this section to demonstrate that each cover operates with no identifiable emissions.

(4) For each bypass device, except as provided for in § 60.5411b(a)(4)(ii), you must meet the requirements of paragraph (a)(4)(i) or (ii) of this section.

(i) Set the flow indicator to take a reading at least once every 15 minutes at the inlet to the bypass device that could divert the stream away from the control device and to the atmosphere.

(ii) If the bypass device valve installed at the inlet to the bypass device is secured in the non-diverting position using a car-seal or a lock-and-key type configuration, visually inspect the seal or closure mechanism at least once every month to verify that the valve is maintained in the non-diverting position and the vent stream is not diverted through the bypass device.

(b) *No identifiable emissions test methods and procedures.* If you are required to conduct an inspection of a closed vent system and cover as specified in paragraph (a)(1), (2), or (3) of this section or § 60.5398b(b), you must meet the requirements of paragraphs (b)(1) through (9) of this section after January 22, 2027. You must meet the requirements of paragraphs (b)(1), (2), (4), and (9) of this section for each self-contained process controller at your process controller affected facility as specified at § 60.5390b(a)(2).

(1) *Initial and periodic inspection.* You must conduct initial and periodic no identifiable emissions inspections as specified in paragraphs (b)(1)(i) through (iii) of this section, as applicable.

(i) You must conduct inspections for no identifiable emissions from your covers and closed vent systems at your well, centrifugal compressor, reciprocating compressor, process controller, pump, or storage vessel affected facility, using the procedures for conducting OGI inspections in § 60.5397b(c)(7). As an alternative you may conduct inspections in accordance with Method 21 of appendix A-7 to this part. Monitoring must be conducted at the same frequency as specified for fugitive emissions components affected facilities located at the same type of site, as specified in § 60.5397b(g).

(ii) For covers and closed vent systems located at onshore natural gas processing plants, OGI inspections for no identifiable emissions must be conducted initially and bimonthly in accordance with appendix K to this part. As an alternative you must conduct quarterly inspections for no identifiable emissions in accordance with Method 21 of appendix A-7 to this part.

(iii) For your self-contained process controller, you must conduct initial and quarterly inspections for no identifiable emissions using the procedures for conducting OGI inspections in § 60.5397b(c)(7). As an alternative you may conduct quarterly inspections in accordance with Method 21 of appendix A-7 to this part.

(2) *OGI application.* Where OGI is used, the closed vent system, cover, or self-contained process controller is determined to operate with no identifiable emissions if no emissions are imaged during the inspection. Emissions imaged by OGI constitute a deviation of the no identifiable emissions standard until an OGI inspection conducted in accordance with paragraph (b)(1) of this section determines that the closed vent system, cover, or self-contained process controller, as applicable, operates with no identifiable emissions.

(3) *AVO application.* Where AVO inspections are required, the closed vent system or cover is determined to operate with no identifiable emissions if no emissions are detected by AVO. Emissions detected by AVO constitute a deviation of the no identifiable emissions standard until an AVO inspection determines that the closed vent system or cover operates with no identifiable emissions.

(4) *Method 21 application.* Where Method 21 of appendix A-7 to this part is used for the inspection, the requirements of paragraphs (b)(4)(i) through (vii) of this section apply.

(i) The detection instrument must meet the performance criteria of Method 21 of appendix A-7 to this part, except that the instrument response factor criteria in section 8.1.1 of Method 21 must be for the average composition of the fluid and not for each individual organic compound in the stream.

(ii) You must calibrate the detection instrument before use on each day of its use by the procedures specified in Method 21 of appendix A-7 to this part.

(iii) Calibration gases must be as specified in paragraphs (b)(4)(iii)(A) and (B) of this section.

(A) Zero air (less than 10 parts per million by volume hydrocarbon in air).

(B) A mixture of methane in air at a concentration less than 500 ppmv.

(iv) You may choose to adjust or not adjust the detection instrument readings to account for the background organic concentration level. If you choose to adjust the instrument readings for the background level, you must determine the background level value according to the procedures in Method 21 of appendix A-7 to this part.

(v) Your detection instrument must meet the performance criteria specified in paragraphs (b)(4)(v)(A) and (B) of this section.

(A) Except as provided in paragraph (b)(4)(v)(B) of this section, the detection instrument must meet the performance criteria of Method 21 of appendix A-7 to this part, except the instrument response factor criteria in section 8.1.1 of Method 21 must be for the average composition of the process fluid, not each individual volatile organic compound in the stream. For process streams that contain nitrogen, air, or other inerts that are not organic hazardous air pollutants or volatile organic compounds, you must calculate the average stream response factor on an inert-free basis.

(B) If no instrument is available that will meet the performance criteria specified in paragraph (b)(4)(v)(A) of this section, you may adjust the instrument readings by multiplying by the average response factor of the process fluid, calculated on an inert-free basis, as described in paragraph (b)(4)(v)(A) of this section.

(vi) You must determine if a potential leak interface operates with no identifiable emissions using the applicable procedure specified in paragraph (b)(4)(vi)(A) or (B) of this section.

(A) If you choose not to adjust the detection instrument readings for the background organic concentration level, then you must directly compare the maximum organic concentration value measured by the detection instrument to the applicable value for the potential leak interface as specified in paragraph (b)(4)(vii) of this section.

(B) If you choose to adjust the detection instrument readings for the background organic concentration level, you must compare the value of the arithmetic difference between the maximum organic concentration value measured by the instrument and the background organic concentration value as determined in paragraph (b)(4)(iv) of this section with the applicable value for the potential leak interface as specified in paragraph (b)(4)(vii) of this section.

(vii) A closed vent system, cover, or self-contained process controller is determined to operate with no identifiable emissions if the organic concentration value determined in paragraph (b)(4)(vi) of this section is less than 500 ppmv. An organic concentration value determined in paragraph (b)(4)(vi) of this section of greater than or equal to 500 ppmv constitutes a deviation of the no identifiable emissions standard until an inspection conducted in accordance with paragraph (b)(4) of this section determines that the closed vent system, cover, or self-contained process controller, as applicable, operates with no identifiable emissions.

(5) *Repairs.* Whenever emissions or a defect is detected, you must repair the emissions or defect as soon as practicable according to the requirements of paragraphs (b)(5)(i) through (iii) of this section, except as provided in paragraph (b)(6) of this section.

(i) A first attempt at repair must be made no later than 5 calendar days after the emissions or defect is detected.

(ii) Repair must be completed no later than 30 calendar days after the emissions or defect is detected.

(iii) For covers, grease or another substance compatible with the gasket material must be applied to deteriorating or cracked gaskets to improve the seal while awaiting repair.

(6) *Delay of repair.* Delay of repair of a closed vent system or cover for which emissions 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 emissions likely to result from delay of repair. You must complete repair of such equipment by the end of the next shutdown.

(7) *Unsafe to inspect requirements.* You may designate any parts of the closed vent system or cover as unsafe to inspect if the requirements of paragraphs (b)(7)(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.

(8) *Difficult to inspect requirements.* You may designate any parts of the closed vent system or cover as difficult to inspect if the requirements of paragraphs (b)(8)(i) and (ii) of this section are met. Difficult to inspect parts are exempt from the inspection requirements of paragraphs (a)(1) through (3) of this section.

(i) You determine that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface.

(ii) You have a written plan that requires inspection of the equipment at least once every 5 years.

(9) *Records and reports.* You must maintain records of all inspection results as specified in § 60.5420b(c)(8) through (10). You must submit the reports as specified in § 60.5420b(b)(11).

§ 60.5417b What are the continuous monitoring requirements for my control devices?

You must meet the requirements of this section to demonstrate continuous compliance for each control device used to meet emission standards for your well, centrifugal compressor, reciprocating compressor, process controller, pump, storage vessel, and process unit equipment affected facilities.

(a) For each control device used to comply with the emission reduction standard in § 60.5377b(b) for well affected facilities, § 60.5380b(a)(1) for centrifugal compressor affected facilities, § 60.5385b(d)(2) for reciprocating compressor affected facilities, § 60.5390b(b)(3) for your process controller affected facility in Alaska, § 60.5393b(b)(3) for your pumps affected facility, § 60.5395b(a)(2) for your storage vessel affected facility, or either § 60.5400b(f) or § 60.5401b(e) for your process equipment affected facility, you must install and operate a continuous parameter monitoring system for each control device as specified in paragraphs (c) through (h) of this section, except as provided for in paragraph (b) of this section. If you install and operate a flare in accordance with § 60.5412b(a)(3), you are exempt from the requirements of paragraph (f) of this section. If you operate an enclosed combustion device or flare using an alternative test method approved under § 60.5412b(d), you must operate the control device as specified in paragraph (i) of this section instead of using the procedures specified in paragraphs (c) through (h) of this section. You must keep records and report in accordance with paragraph (j) 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.

(1) A boiler or process heater in which all vent streams are introduced with the primary fuel or are used as the primary fuel.

(2) A boiler or process heater with a design heat input capacity equal to or greater than 44 megawatts.

(c) You must meet the specifications and requirements of paragraphs (c)(1) through (4) of this section.

(1) Except for continuous parameter monitoring systems used to detect the presence of a pilot or combustion flame, each continuous parameter monitoring system must measure data values at least once every hour and record the values for each parameter as required in paragraphs (c)(1)(i) or (ii) of this section. Continuous parameter monitoring systems used to detect the presence of a pilot or combustion flame must record a reading at least once every 5 minutes.

(i) Each measured data value.

(ii) Each block average value for each 1-hour period or shorter periods calculated from all measured data values during each period.

(2) You must prepare a monitoring plan that covers each control device for affected facilities within each company-defined area. The monitoring plan must address the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraphs (c)(2)(i) through (v) of this section. You must install, calibrate, operate, and maintain each continuous parameter monitoring system in accordance with the procedures in your monitoring plan. Heat sensing monitoring devices that indicate the continuous ignition of a pilot or combustion flame are exempt from the calibration, quality assurance and quality control requirements of this section.

(i) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations.

(ii) Sampling interface (*e.g.*, thermocouple) location such that the monitoring system will provide representative measurements.

(iii) Equipment performance checks, system accuracy audits, or other audit procedures.

(iv) Ongoing operation and maintenance procedures in accordance with provisions in § 60.13(b).

(v) Ongoing recordkeeping procedures in accordance with provisions in § 60.7(f).

(3) You must conduct the continuous parameter monitoring system equipment performance checks, system accuracy audits, or other audit procedures specified in the monitoring plan at least once every 12 months.

(4) You must conduct a performance evaluation of each continuous parameter monitoring system in accordance with the monitoring plan. Heat sensing monitoring devices that indicate the continuous ignition of a pilot or combustion flame are exempt from the calibration, quality assurance and quality control requirements of this section.

(d) You must install, calibrate, operate, and maintain a device equipped with a continuous recorder to measure the values of operating parameters appropriate for the control device as specified in paragraphs (d)(1) through (8) of this section, as applicable. Instead of complying with the requirements in paragraphs (d)(1) through (8) of this section, you may install 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 to demonstrate compliance with the applicable performance requirement specified in § 60.5412b(a)(1). The monitor must meet the requirements of Performance Specification 8 or 9 of appendix B to this part. You must install, calibrate, and maintain the monitor according to the manufacturer's specifications and the requirements in Performance Specification 8 or 9. You may also request approval from the Administrator to monitor different operating parameters than those specified in paragraphs (d)(1) through (8) of this section in accordance with § 60.13(i).

(1) For an enclosed combustion device that demonstrates during the performance test conducted under § 60.5413b(b) that combustion zone temperature is an accurate indicator of performance, a temperature monitoring device equipped with a continuous recorder. The monitoring device must have a minimum accuracy of ± 1 percent of the temperature being monitored in degrees Celsius, or ± 2.5 °C, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature. You must also comply with the requirements of paragraphs (d)(8)(i), (iv), and (v) of this section.

(2) For a catalytic vapor incinerator, a temperature monitoring device equipped with a continuous recorder. The device must be capable of monitoring temperature at two locations and have a minimum accuracy of ± 1 percent of the temperature being monitored in degrees Celsius, or ± 2.5 °C, whichever value is greater. You must install one temperature sensor in the vent stream at the nearest feasible point to the catalyst bed inlet, and you must install a second temperature sensor in the vent stream at the nearest feasible point to the catalyst bed outlet.

(3) For a boiler or process heater, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device must have a minimum accuracy of ± 1 percent of the temperature being monitored in degrees Celsius, or ± 2.5 °C, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature.

(4) For a condenser, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device must have a minimum accuracy of ± 1 percent of the temperature being monitored in degrees Celsius, or ± 2.5 °C, whichever value is greater. You must install the temperature sensor at a location in the exhaust vent stream from the condenser.

(5) For a regenerative-type carbon adsorption system, a continuous monitoring system that meets the specifications in paragraphs (d)(5)(i) and (ii) of this section. You also must monitor the design carbon service life established using a design analysis performed as specified in § 60.5413b(c)(2).

(i) The continuous parameter monitoring system must measure and record the average total regeneration stream mass flow or volumetric flow during each carbon bed regeneration cycle. The flow

sensor must have a measurement sensitivity of 5 percent of the flow rate or 10 cubic feet per minute, whichever is greater. You must check the mechanical connections for leakage at least every month, and you must perform a visual inspection at least every 3 months of all components of the flow continuous parameter monitoring system for physical and operational integrity and all electrical connections for oxidation and galvanic corrosion if your flow continuous parameter monitoring system is not equipped with a redundant flow sensor; and

(ii) The continuous parameter monitoring system must measure and record the average carbon bed temperature for the duration of the carbon bed steaming cycle and measure the actual carbon bed temperature after regeneration and within 15 minutes of completing the cooling cycle. The temperature monitoring device must have a minimum accuracy of ± 1 percent of the temperature being monitored in degrees Celsius, or ± 2.5 °C, whichever value is greater.

(6) For a nonregenerative-type carbon adsorption system, you must monitor the design carbon replacement interval established using a design analysis performed as specified in § 60.5413b(c)(3). The design carbon replacement interval must be based on the total carbon working capacity of the control device and source operating schedule.

(7) For a combustion control device whose model is tested under § 60.5413b(d), continuous monitoring systems as specified in paragraphs (d)(8)(i) through (iv) and (d)(8)(vi) of this section and visible emission observations conducted as specified in paragraph (d)(8)(v) of this section.

(8) For an enclosed combustion device, other than those listed in paragraphs (d)(1) through (3) and (7) of this section, or for a flare, continuous monitoring systems as specified in paragraphs (d)(8)(i) through (iv) of this section and visible emission observations conducted as specified in paragraph (d)(8)(v) of this section. Additionally, for enclosed combustion devices or flares that are air-assisted or steam-assisted, the continuous monitoring systems specified in paragraph (d)(8)(vi) of this section.

(i) After January 22, 2027, continuously monitor at least once every five minutes for the presence of a pilot flame or combustion flame using a device (including, but not limited to, a thermocouple, ultraviolet beam sensor, or infrared sensor) capable of detecting that the pilot or combustion flame is present at all times. After January 22, 2027, an alert must be sent to the nearest control room whenever the pilot or combustion flame is unlit. Continuous monitoring systems used for the presence of a pilot flame or combustion flame are not subject to a minimum accuracy requirement beyond being able to detect the presence or absence of a flame and are exempt from the calibration requirements of this section.

(ii) Except as provided in this paragraph (d)(8)(ii) and paragraph (d)(8)(iii) of this section, use one of the following methods to continuously determine the NHV of the inlet gas to the enclosed combustion device or flare at standard conditions. If the only inlet gas stream to the enclosed combustion device or flare is associated gas from a well affected facility, the NHV of the inlet stream is considered to be sufficiently above the minimum required NHV for the inlet gas, and you are not required to conduct the continuous monitoring in this paragraph (d)(8)(ii) of this section or the demonstration in paragraph (d)(8)(iii) of this section.

(A) A calorimeter with a minimum accuracy of ± 2 percent of span.

(B) A gas chromatograph that meets the requirements in paragraphs (d)(8)(ii)(B)(1) through (5) of this section.

(1) You must follow the procedure in Performance Specification 9 of appendix B of this part, except that a single daily mid-level calibration check can be used (rather than triplicate analysis), the multi-point calibration can be conducted quarterly (rather than monthly), and the sampling line temperature must be maintained at a minimum

temperature of 60 °C (rather than 120 °C). Calibration gas cylinders must be certified to an accuracy of 2 percent and traceable to National Institute of Standards and Technology (NIST) standards.

(2) You must meet the accuracy requirements in Performance Specification 9 of appendix B of this part.

(3) You must use a calibration gas or multiple gases that includes the compounds that are reasonably expected to be present in the flare gas stream. If multiple calibration gases are necessary to cover all compounds, you must calibrate the instrument on all of the gases. You may only use the compounds used to calibrate the gas chromatograph in the calculation of the vent gas NHV.

(4) In lieu of the calibration gas described in paragraph (d)(8)(ii)(B)(3) of this section, you may use a surrogate calibration gas consisting of hydrogen and C1 through C5 normal hydrocarbons. All of the calibration gases may be combined in one cylinder. If multiple calibration gases are necessary to cover all compounds, you must calibrate the instrument on all of the gases. Use the response factor for the nearest normal hydrocarbon (*i.e.*, n-alkane) in the calibration mixture to quantify unknown components detected in the analysis. Use the response factor for n-pentane to quantify unknown components detected in the analysis that elute after n-pentane.

(5) To determine the NHV of the vent gas, determine the product of the volume fraction of the individual component in the vent gas and the net heating value of that individual component. Sum the products for all components in the vent gas to determine the NHV for the vent gas. For the net heating value of each individual component, use the net heating value at 25 °C and 1 atmosphere.

(C) A mass spectrometer that meets the requirements in paragraphs (d)(8)(ii)(C)(1) through (6) of this section.

(1) You must meet applicable requirements in Performance Specification 9 of appendix B of this part for continuous monitoring system acceptance including, but not limited to, performing an initial multi-point calibration check at three concentrations following the procedure in Section 10.1. A single daily mid-level calibration check can be used (rather than triplicate analysis), the multi-point calibration can be conducted quarterly (rather than monthly), and the sampling line temperature must be maintained at a minimum temperature of 60 °C (rather than 120 °C). Calibration gas cylinders must be certified to an accuracy of 2 percent and traceable to NIST standards.

(2) The average instrument calibration error (CE) for each calibration compound at any calibration concentration must not differ by more than 10 percent from the certified cylinder gas value. The CE for each component in the calibration blend must be calculated using the following equation:

Equation 1 to paragraph (d)(8)(ii)(C)(2)

$$CE = \frac{C_m - C_a}{C_a} \times 100$$

Where:

Cm = Average instrument response (ppm).

Ca = Certified cylinder gas value (ppm).

(3) You must use a calibration gas or multiple gases that includes the compounds that are reasonably expected to be present in the flare gas stream. If multiple calibration gases are necessary to cover all compounds, you must calibrate the instrument on all of the gases. You may only use the compounds used to calibrate the mass spectrometer in the calculation of the vent gas NHV.

(4) In lieu of the calibration gas described in paragraph (d)(8)(ii)(C)(3) of this section, you may use a surrogate calibration gas consisting of hydrogen and C1 through C5 normal hydrocarbons. All of the calibration gases may be combined in one cylinder. If multiple calibration gases are necessary to cover all compounds, you must calibrate the instrument on all of the gases. For unknown gas components that have similar analytical mass fragments to calibration compounds, you may report the unknowns as an increase in the overlapped calibration gas compound. For unknown compounds that produce mass fragments that do not overlap calibration compounds, you may use the response factor for the nearest molecular weight hydrocarbon in the calibration mix to quantify the unknown component. You may use the response factor for n-pentane to quantify any unknown components detected with a higher molecular weight than n-pentane.

(5) You must perform an initial calibration to identify mass fragment overlap and response factors for the target compounds.

(6) To determine the NHV of the vent gas, determine the product of the volume fraction of the individual component in the vent gas and the net heating value of that individual component. Sum the products for all components in the vent gas to determine the NHV for the vent gas. For the net heating value of each individual component, use the net heating value at 25 °C and 1 atmosphere.

(D) A grab sampling system capable of collecting an evacuated canister sample for subsequent compositional analysis at least once every eight hours. Subsequent compositional analysis of the samples must be performed according to ASTM D1945-14 (R2019) (incorporated by reference, see § 60.17). To determine the NHV of the vent gas, determine the product of the volume fraction of the individual component in the vent gas and the net heating value of that individual component. Sum the products for all components in the vent gas to determine the NHV for the vent gas. For the net heating value of each individual component, use the net heating value at 25 °C and 1 atmosphere.

(iii) For an unassisted or pressure-assisted flare or enclosed combustion device, if you demonstrate according to the methods described in paragraphs (d)(8)(iii)(A) through (F) of this section that the NHV of the inlet gas to the enclosed combustion device or flare consistently exceeds the applicable operating limit specified in § 60.5415b(f)(1)(vii)(B) or (C), continuous monitoring of the NHV is not required, but you must conduct the ongoing sampling in paragraph (d)(8)(iii)(G) of this section. For flares and enclosed combustion devices that use only perimeter assist air and do not use steam assist or pre-mix assist air, if you demonstrate according to the methods described in paragraphs (d)(8)(iii)(A) through (F) of this section that the NHV of the inlet gas to the enclosed combustion device or flare consistently exceeds 300 Btu/scf, continuous monitoring of the NHV is not required, but you must conduct the ongoing sampling in paragraph (d)(8)(iii)(G) of this section. For an unassisted or pressure-assisted flare or

enclosed combustion device, in lieu of conducting the demonstration outlined in paragraphs (d)(8)(iii)(A) through (D) of this section, you may conduct the demonstration outlined in paragraph (d)(8)(iii)(H) of this section, but you must still comply with paragraphs (d)(8)(iii)(E) through (G) of this section.

(A) Continuously monitor or collect a sample of the inlet gas to the enclosed combustion device or flare twice daily to determine the average NHV of the gas stream for 14 consecutive operating days. If you do not continuously monitor the NHV, the minimum time of collection for each individual sample be at least one hour. Consecutive samples must be separated by at least 6 hours. If inlet gas flow is intermittent such that there are not at least 28 samples over the 14 operating day period, you must continue to collect samples of the inlet gas beyond the 14 operating day period until you collect a minimum of 28 samples.

(B) If you collect samples twice per day, count the number of samples where the NHV value is less than 1.2 times the applicable operating limit specified in § 60.5415b(f)(1)(vii)(B), (C), or paragraph (d)(8)(iii) of this section (*i.e.*, values that are less than 240, 360, or 960 Btu/scf, as applicable) during the sample collection period in paragraph (d)(8)(iii)(A) of this section.

(C) If you continuously sample the inlet stream for 14 days, count the number of hourly average NHV values that are less than the applicable operating limit specified in § 60.5415b(f)(1)(vii)(B), § 60.5415b(f)(1)(vii)(C)(1), or paragraph (d)(8)(iii) of this section (*i.e.*, values that are less than 200, 300, or 800 Btu/scf, as applicable), during the sample collection period in paragraph (d)(8)(iii)(A) of this section.

(D) If there are no samples counted under paragraph (d)(8)(iii)(B) of this section or there are no hourly values counted under paragraph (d)(8)(iii)(C) of this section, the gas stream is considered to consistently exceed the applicable NHV operating limit and on-going continuous monitoring is not required.

(E) If process operations are revised that could impact the NHV of the gas sent to the enclosed combustion device or flare, such as the removal or addition of process equipment, and at any time the Administrator requires, re-evaluation of the gas stream must be performed according to paragraphs (d)(8)(iii)(A) through (D) of this section to ensure the gas stream still consistently exceeds the applicable operating limit specified in § 60.5415b(f)(1)(vii)(B), (f)(1)(vii)(C)(1), or paragraph (d)(8)(iii) of this section.

(F) When collecting samples under paragraph (d)(8)(iii)(A) of this section, the owner or operator must account for any sources of inert gases that can be sent to the enclosed combustion device or flare (*e.g.*, streams from compressors in acid gas service, streams from enhanced oil recovery facilities). The report in § 60.5420b(b)(11)(v)(I) and the records of the demonstration in § 60.5420b(c)(11)(vi) must note whether the enclosed combustion device or flare has the potential to receive inert gases, and if so, whether the sampling included periods where the highest percentage of inert gases were sent to the enclosed combustion device or flare. If the introduction of inerts is intermittent and does not occur during the initial demonstration, the introduction of inerts will be considered a revision to process operations that triggers a re-evaluation under paragraph (d)(8)(iii)(E) of this section. If conditions at the site did not allow sampling during periods where the introduction of inert gases was at the highest percentage possible, increasing the percentage of inerts will be considered a revision to process operations that triggers a re-evaluation under paragraph (d)(8)(iii)(E) of this section.

(G) You must collect three samples of the inlet gas to the enclosed combustion device or flare at least once every 5 years. The minimum time of collection for each individual sample must be at least one hour. The samples must be taken during the period with the lowest expected NHV

(i.e., the period with the highest percentage of inerts). The first set of periodic samples must be taken, or continuous monitoring commenced, no later than 60 calendar months following the last sample taken under paragraph (d)(8)(iii)(A) of this section. Subsequent periodic samples must be taken, or continuous monitoring commenced, no later than 60 calendar months following the previous sample. If any sample has an NHV value less than 1.2 times the applicable operating limit specified in § 60.5415b(f)(1)(vii)(B), § 60.5415b(f)(1)(vii)(C), or paragraph (d)(8)(iii) of this section (i.e., values that are less than 240, 360, or 960 Btu/scf, as applicable), you must conduct the monitoring required by paragraph (d)(8)(ii) of this section.

(H) You may request an alternative test method under § 60.5412b(d) to demonstrate that the flare or enclosed combustion device reduces methane and VOC in the gases vented to the device by 95.0 percent by weight or greater. You must use an alternative test method that demonstrates compliance with the combustion efficiency limit; you may not use an alternative test method that demonstrates compliance with NHV_{cz} and NHV_{dil} in lieu of measuring combustion efficiency directly. You must measure data values at the frequency specified in the alternative test method and conduct the quality assurance and quality control requirements outlined in the alternative test method at the frequency outlined in the alternative test method. You must monitor the combustion efficiency of the flare continuously for 14 days. If there are no values of the combustion efficiency measured by the alternative test method that are less than 95.0 percent, the gas stream is considered to consistently exceed the applicable NHV operating limit, and you are not required to continuously monitor the NHV of the inlet gas to the flare or enclosed combustion device.

(iv) Except as noted in paragraphs (d)(8)(iv)(A) through (E) of this section, a continuous parameter monitoring system for measuring the flow of gas to the enclosed combustion device or flare. You may use direct flow meters or other parameter monitoring systems combined with engineering calculations, such as inlet line pressure, line size, and burner nozzle dimensions, to satisfy this requirement. The monitoring instrument must have an accuracy of ± 10 percent or better at the maximum expected flow rate.

(A) Pressure-assisted flares and pressure-assisted enclosed combustion devices are not required to have a continuous parameter monitoring system for measuring the inlet flow of gas to the device if you install, calibrate, maintain, and operate a backpressure regulator valve calibrated to open at the minimum pressure set point corresponding to the minimum inlet gas flow rate. The set point must be consistent with manufacturer specifications for minimum flow or pressure and must be supported by an engineering evaluation. At least annually, you must confirm that the backpressure regulator valve set point is correct and consistent with the engineering evaluation and manufacturer specifications and that the valve fully closes when not in the open position.

(B) Unassisted flares are not required to have a continuous parameter monitoring system for measuring the inlet flow of gas to the device if you meet the conditions in paragraphs (d)(8)(iv)(B)(1) and (2) of this section.

(1) You must demonstrate, based on the maximum potential pressure of units manifolded to the flare and applicable engineering calculations for the manifolded closed vent system, that the maximum flow rate to the flare cannot cause the flare tip velocity to exceed 18.3 meter/second (60 feet/second). If there are changes to the process or control device that can be reasonably expected to impact the maximum flow rate to the flare, you must conduct a new demonstration to determine whether the maximum flow rate to the flare is less than 18.3 meter/second (60 feet/second).

(2) You must install, calibrate, maintain, and operate a backpressure regulator valve calibrated to open at the minimum pressure set point corresponding to the minimum inlet gas flow rate. The set point must be consistent with manufacturer specifications for minimum flow or pressure and must be supported by an engineering evaluation. At least annually, you must confirm that the backpressure regulator valve set point is correct and consistent with the engineering evaluation and manufacturer specifications and that the valve fully closes when not in the open position.

(C) Unassisted enclosed combustion devices are not required to have a continuous parameter monitoring system for measuring the inlet flow of gas to the device if you meet the conditions in paragraphs (d)(8)(iv)(C)(1) and (2) of this section.

(1) You must demonstrate, based on the maximum potential pressure of units manifolded to the enclosed combustion device and applicable engineering calculations for the manifolded closed vent system, that the maximum flow rate to the enclosed combustion device cannot cause the maximum inlet flow rate established in accordance with paragraph (f)(1) of this section to be exceeded. If there are changes to the process or control device that can be reasonably expected to impact the maximum flow rate to the enclosed combustion device, you must conduct a new demonstration to determine whether the maximum flow rate to the enclosed combustor is less than the maximum inlet flow rate established in accordance with paragraph (f)(1) of this section.

(2) You must install, calibrate, maintain, and operate a backpressure regulator valve calibrated to open at the minimum pressure set point corresponding to the minimum inlet gas flow rate. The set point must be consistent with manufacturer specifications for minimum flow or pressure and must be supported by an engineering evaluation. At least annually, you must confirm that the backpressure regulator valve set point is correct and consistent with the engineering evaluation and manufacturer specifications and that the valve fully closes when not in the open position.

(D) Air-assisted flares or enclosed combustion devices that use only perimeter assist air and have no assist steam or premix assist air are not required to have a continuous parameter monitoring system for measuring the inlet flow of gas to the device or the flow of assist air if you meet the conditions in paragraphs (d)(8)(iv)(D)(1) and (2) of this section. For these flares and enclosed combustion devices, NHV_{cz} is assumed to be equal to the vent gas NHV .

(1) You must install, calibrate, maintain, and operate a backpressure regulator valve calibrated to open at the minimum pressure set point corresponding to the minimum inlet gas flow rate. The set point must be consistent with manufacturer specifications for minimum flow or pressure and must be supported by an engineering evaluation. At least annually, you must confirm that the backpressure regulator valve set point is correct and consistent with the engineering evaluation and manufacturer specifications and that the valve fully closes when not in the open position.

(2) You must demonstrate, based on the maximum flow rate of perimeter assist air to the enclosed combustion device or flare and applicable engineering calculations, that the NHV_{dil} can never be less than the minimum required NHV_{dil} . The demonstration must clearly document why the maximum flow rate of perimeter assist air will never exceed the rate used in the demonstration. You must use the minimum flow rate of vent gas allowed by your backpressure regulator valve and the minimum expected value of the NHV of the inlet gas to the enclosed combustion device or flare based on previous

sampling results or process knowledge of the streams sent to the enclosed combustion device or flare in your demonstration. You must update this demonstration if there are changes to the backpressure regulator valve, the backpressure regulator valve set point, or the maximum flow rate of perimeter assist air. You must also update this demonstration if any sampling results of the NHV of the inlet gas to the enclosed combustion device or flare under paragraphs (d)(8)(ii) or (iii) of this section are lower than the NHV vent gas value used in your demonstration.

(E) Air-assisted flares or enclosed combustion devices that use only premix assist air and have no assist steam or perimeter assist air are not required to have a continuous parameter monitoring system for measuring the inlet flow of gas to the device or the flow of assist air if you meet the conditions in paragraphs (d)(8)(iv)(E)(1) and (2) of this section.

(1) You must install, calibrate, maintain, and operate a backpressure regulator valve calibrated to open at the minimum pressure set point corresponding to the minimum inlet gas flow rate. The set point must be consistent with manufacturer specifications for minimum flow or pressure and must be supported by an engineering evaluation. At least annually, you must confirm that the backpressure regulator valve set point is correct and consistent with the engineering evaluation and manufacturer specifications and that the valve fully closes when not in the open position.

(2) You must demonstrate, based on the maximum flow rate of premix assist air to the enclosed combustion device or flare and applicable engineering calculations, that the NHV_{cz} will never be less than the minimum required NHV_{cz} . The demonstration must clearly document why the maximum flow rate of premix assist air will never exceed the rate used in the demonstration. You must use the minimum flow rate of vent gas allowed by your backpressure regulator valve in and the minimum expected value of the NHV of the inlet gas to the enclosed combustion device or flare based on previous sampling results or process knowledge of the streams sent to the enclosed combustion device or flare in your demonstration. You must update this demonstration if there are changes to the backpressure regulator valve, the backpressure regulator valve set point, or the maximum flow rate of premix assist air. You must also update this demonstration if any sampling results of the NHV of the inlet gas to the enclosed combustion device or flare under paragraphs (d)(8)(ii) or (iii) of this section are lower than the NHV vent gas value used in your demonstration.

(v) Conduct inspections monthly and at other times as requested by the Administrator to monitor for visible emissions from the combustion device using section 11 of Method 22 of appendix A of this part or conduct visible emissions monitoring according to paragraph (h) of this section. The observation period shall be 15 minutes or once the amount of time visible emissions is present has exceeded 1 minute. Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period.

(vi) If you use a flare or enclosed combustion device that is air-assisted or steam-assisted, you must also meet the following requirements.

(A) Except as allowed by paragraph (d)(8)(iv)(E) of this section, you must monitor and calculate NHV_{cz} as specified in § 63.670(m) of this chapter. Additionally, for flares and enclosed combustion devices that use only perimeter assist air and do not use steam assist or premix assist air, the NHV_{cz} is equal to the vent gas NHV. When NHV_{cz} is equal to the vent gas NHV, you

are not required to continuously monitor NHV_{cz} if you meet the requirements in paragraph (d)(8)(iii) of this section.

(B) Except as allowed by paragraph (d)(8)(iv)(D) of this section, for each flare using perimeter assist air, you must also monitor and calculate NHV_{dil} as specified in § 63.670(n) of this chapter. If the only assist air provided to the flare or enclosed combustion control device is perimeter assist air intentionally entrained in lower and/or upper steam at the flare tip and the effective diameter is 9 inches or greater, you are only required to comply with the NHV_{cz} limit specified in paragraph (f)(8)(vi)(A) of this section.

(C) Except as allowed by paragraph (d)(8)(iv) of this section, you must monitor the flare vent gas and assist gas as specified in § 63.670(i) of this chapter.

(D) You must determine the flare vent gas net heating value as specified in § 63.670(l) of this chapter using one of the methods specified in paragraph (d)(8)(ii) of this section. Where the phrase "petroleum refinery" is used, for purposes of this subpart, it will refer to flares controlling an affected facility under this subpart. If you are not required to continuously monitor the NHV of the inlet gas because you have demonstrated that it consistently exceeds the applicable operating limit as provided in paragraph (d)(8)(iii) of this section, you must use the lowest net heating value measured in the sampling program in paragraph (d)(8)(iii) of this section for the calculations performed in paragraphs (d)(8)(vi)(A) and (B). You must update this value if a subsequent sampling result of the NHV of the inlet gas to the enclosed combustion device or flare under paragraph (d)(8)(iii) of this section is lower than the NHV vent gas value used in your calculations.

(e) Calculate the value of the applicable monitored parameter in accordance with paragraphs (e)(1) through (5) of this section.

(1) You must calculate the daily average value for condenser outlet temperature for each operating day, using the data recorded by the monitoring system. If the emissions unit operation is continuous, the operating day is a 24-hour period. If the emissions unit operation is not continuous, the operating day is the total number of hours of control device operation per 24-hour period. Valid data points must be available for 75 percent of the operating hours in an operating day to compute the daily average.

(2) You must use the 5-minute readings from the heat sensing devices to assess the presence of a pilot or combustion flame.

(3) You must use the regeneration cycle time (*i.e.*, duration of the carbon bed steaming cycle) for each regenerative-type carbon adsorption system to calculate the average parameter to compare with the maximum steam mass flow or volumetric flow during each carbon bed regeneration cycle and the maximum carbon bed temperature during the steaming cycle. The carbon bed temperature after the regeneration cycle should not be averaged; you must use the carbon bed temperature measured within 15 minutes of completing the cooling cycle to compare with the minimum carbon bed temperature after the regeneration cycle.

(4) You must use 15-minute blocks to calculate NHV_{cz} and NHV_{dil} .

(5) For all operating parameters others than those described in paragraphs (e)(1) through (4) of this section, you must calculate the 3-hour rolling average of each monitored parameter. For each operating hour, calculate the hourly value of the operating parameter from your continuous monitoring system. Average the three most recent hours of data to determine the 3-hour average. Determine the 3-hour rolling average by recalculating the 3-hour average each hour.

(f) For each operating parameter monitor installed in accordance with the requirements of paragraph (d) of this section, you must comply with paragraph (f)(1) of this section for all control devices. When condensers are installed, you must also comply with paragraph (f)(2) of this section.

(1) You must establish a minimum operating parameter value or a maximum operating parameter value, as appropriate for the control device, to define the conditions at which the control device must be operated to continuously achieve the applicable performance requirements of § 60.5412b(a)(1) or (2). You must establish each minimum or maximum operating parameter value as specified in paragraphs (f)(1)(i) through (iv) of this section.

(i) If you conduct performance tests in accordance with the requirements of § 60.5413b(b) to demonstrate that the control device achieves the applicable performance requirements specified in § 60.5412b(a)(1) or (2), then you must establish the minimum operating parameter value or the maximum operating parameter value based on values measured during the performance test and supplemented, as necessary, by a condenser or carbon adsorption system design analysis or control device manufacturer recommendations or a combination of both. If you operate an enclosed combustion device, you must establish the maximum inlet flow rate based on values measured during the performance test and you may establish the minimum inlet flow rate based on control device manufacturer recommendations.

(ii) If you use a condenser or carbon adsorption system design analysis in accordance with the requirements of § 60.5413b(c) to demonstrate that the control device achieves the applicable performance requirements specified in § 60.5412b(a)(2), then you must establish the minimum operating parameter value or the maximum operating parameter value based on the design analysis and supplemented, as necessary, by the manufacturer's recommendations.

(iii) If you operate a control device where the performance test requirement was met under § 60.5413b(d) to demonstrate that the control device achieves the applicable performance requirements specified in § 60.5412b(a)(1), then your control device inlet gas flow rate must be equal to or greater than the minimum inlet gas flow rate and equal to or less than the maximum inlet gas flow rate determined by the manufacturer.

(iv) If you operate an enclosed combustion device where the combustion zone temperature is not an indicator of destruction efficiency or a control device where the performance test requirement was met under § 60.5413b(d), you must maintain the NHV of the gas sent to the enclosed combustion device, the NHV_{cz} , and the NHV_{dil} above the applicable limits specified in paragraphs § 60.5412b(a)(1)(iv)(A) through (D).

(2) If you use a condenser as specified in paragraph (d)(1)(v) of this section, you must establish a condenser performance curve showing the relationship between condenser outlet temperature and condenser control efficiency, according to the requirements of paragraphs (f)(2)(i) and (ii) of this section.

(i) If you conduct a performance test in accordance with the requirements of § 60.5413b(b) to demonstrate that the condenser achieves the applicable performance requirements of § 60.5412b(a)(2), then the condenser performance curve must be based on values measured during the performance test and supplemented as necessary by control device design analysis, or control device manufacturer's recommendations, or a combination or both.

(ii) If you use a control device design analysis in accordance with the requirements of § 60.5413b(c)(1) to demonstrate that the condenser achieves the applicable performance requirements specified in § 60.5412b(a)(2), then the condenser performance curve must be based on the condenser design analysis and supplemented, as necessary, by the control device manufacturer's recommendations.

(g) A deviation for a control device is determined to have occurred when the monitoring data or lack of monitoring data result in any one of the criteria specified in paragraphs (g)(1) through (7) of this section being met. If you monitor multiple operating parameters for the same control device during the same operating day and more than one of these operating parameters meets a deviation criterion specified in paragraphs (g)(1) through (7) of this section, then a single excursion is determined to have occurred for the control device for that operating day.

(1) A deviation occurs when the average value of a monitored operating parameter determined in accordance with paragraph (e) of this section is less than the minimum operating parameter limit (and, if applicable, greater than the maximum operating parameter limit) established in paragraph (f)(1) of this section; for flares, when the average value of a monitored operating parameter determined in accordance with paragraph (e) of this section is above the limits specified in § 60.5415b(f)(1)(vii)(B); or when the heat sensing device indicates that there is no pilot or combustion flame present for any time period. If you use a backpressure regulator valve to maintain the inlet gas flow to an enclosed combustion device or flare above the minimum value, a deviation occurs if the annual inspection finds that the backpressure regulator valve set point is not set correctly or indicates that the backpressure regulator valve does not fully close when not in the open position.

(2) If you are subject to § 60.5412b(a)(2), a deviation occurs when the 365-day average condenser efficiency calculated according to the requirements specified in § 60.5415b(f)(1)(ix)(D) is less than 95.0 percent.

(3) If you are subject to § 60.5412b(a)(2) and you have less than 365 days of data, a deviation occurs when the average condenser efficiency calculated according to the procedures specified in § 60.5415b(f)(1)(ix)(D)(1) or (2) is less than 95.0 percent.

(4) A deviation occurs when the monitoring data are not available for at least 75 percent of the operating hours in a day.

(5) If the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device, a deviation occurs when the requirements of paragraph (g)(5)(i) or (ii) of this section are met.

(i) For each bypass line subject to § 60.5411b(a)(4)(i)(A), the flow indicator indicates that flow has been detected and that the stream has been diverted away from the control device to the atmosphere.

(ii) For each bypass line subject to § 60.5411b(a)(4)(i)(B), if the seal or closure mechanism has been broken, the bypass line valve position has changed, the key for the lock-and-key type lock has been checked out, or the car-seal has broken.

(6) For a combustion control device whose model is tested under § 60.5413b(d), a deviation occurs when the conditions of paragraph (g)(4), (5), or (6)(i) through (vi) of this section are met.

(i) The hourly inlet gas flow rate is less than the minimum inlet gas flow rate or greater than the maximum inlet gas flow rate determined by the manufacturer. If you use a backpressure regulator valve to maintain the inlet gas flow above the minimum value, a deviation occurs if the annual inspection finds that the backpressure regulator valve set point is not set correctly or indicates that the backpressure regulator valve does not fully close when not in the open position.

(ii) Results of the monthly visible emissions test conducted under § 60.5413b(e)(3) or monitoring under paragraph (h) of this section indicate visible emissions exceed 1 minute in any 15-minute period.

(iii) There is no indication of the presence of a pilot or combustion flame for any 5-minute time period.

(iv) The control device is not maintained in a leak free condition.

(v) The control device is not operated in accordance with the manufacturer's written operating instructions, procedures and maintenance schedule.

(vi) The NHV of the vent gas, the NHV_{cz} , or the NHV_{dii} is below the applicable limit specified in § 60.5412b(a)(1)(iv).

(7) For an enclosed combustion device or flare subject to paragraph (d)(8) of this section, a deviation occurs when any of the conditions described by paragraphs (g)(1), (4) or (5) of this section are met or when the results of the visible emissions monitoring conducted under paragraph (d)(8)(v) or (h) of this section exceed 1 minute in any 15-minute period.

(h) For enclosed combustion devices and flares, in lieu of conducting a visible emissions observation using Method 22 of appendix A-7 to this part, you may use a video surveillance camera to continuously monitor and record the flare flame according to the requirements in paragraphs (h)(1) through (6) of this section.

(1) You must provide real-time high-definition video surveillance camera output (*i.e.*, at least 720p) at a frame rate of at least 15 frames per second to the control room or other continuously manned location where the camera images may be viewed at the same resolution at any time.

(2) You must record at least one frame every 15 seconds with date and time stamp.

(3) The camera must be located at a reasonable distance above the flare flame at an angle suitable for visual emissions observations. The position of the camera should be such that the sun is not in the field of view.

(4) The camera must be located no more than 400 m (0.25 miles) from the emission source.

(5) Operators must look at the video feed at least once daily for an observation period of at least 1 minute to determine if visible emissions are present. If visible emissions are present during a daily observation, the operator must observe the video feed for 15 minutes or until the amount of time visible emissions is present has exceeded 1 minute, whichever time period is less.

(6) Enclosed combustion devices and flares must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period.

(i) If you use an enclosed combustion device or flare using an alternative test method approved under § 60.5412b(d), you must comply with paragraphs (i)(1) through (6) of this section.

(1) You must measure data values at the frequency specified in the alternative test method.

(2) You must prepare a monitoring plan that covers each control device for affected facilities within each company-defined area. The monitoring plan must address the monitoring system design, data collection, and the quality assurance and quality control elements outlined in the alternative test method and in paragraphs (i)(2)(i) through (iii) of this section. You must operate and maintain each monitoring system in accordance with the procedures in your monitoring plan.

(i) The performance criteria and design specifications for the monitoring system equipment.

(ii) Location of monitoring system in relation to the monitored control device.

(iii) Ongoing reporting and recordkeeping procedures.

(3) You must conduct the quality assurance and quality control requirements outlined in the alternative test method at the frequency outlined in the alternative test method.

(4) If required by § 60.5412b(d)(4), you must conduct the inspections required by paragraph (d)(8)(v) of this section.

(5) If required by § 60.5412b(d)(5), you must install the pilot or combustion flame monitoring system required by paragraph (d)(8)(i) of this section.

(6) A deviation for the control device is determined to have occurred when the monitoring data or lack of monitoring data result in any one of the criteria specified in paragraphs (i)(6)(i) through (v) of this section being met.

(i) A deviation occurs if the combustion efficiency is less than 95.0 percent, the combustion zone NHV is less than 270 Btu/scf, or the NHV dilution parameter is less than 22 Btu/sqft.

(ii) A deviation occurs when the monitoring data are not available for at least 75 percent of the operating hours in a day.

(iii) A deviation occurs when any of the conditions described by paragraph (g)(5) of this section are met.

(iv) If required by paragraph (i)(4) of this section to conduct visible emissions inspections, a deviation occurs when the results of the visible emissions monitoring conducted under paragraph (d)(8)(v) or (h) of this section exceeds 1 minute in any 15-minute period.

(v) After January 22, 2027, if required by paragraph (i)(5) of this section to install a pilot or combustion flame monitoring system, a deviation occurs when there is no indication of the presence of a pilot or combustion flame for any 5-minute period.

(j) You must submit annual reports for control devices as required in § 60.5420b(b)(1) and (11). You must maintain records as specified in § 60.5420b(c)(11).

§ 60.5420b What are my notification, reporting, and recordkeeping requirements?

(a) *Notifications.* You must submit 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 § 60.5365b that was constructed, modified, or reconstructed during the reporting period. You must submit the notification in paragraph (a)(3) of this section if you use an alternative standard for fugitive emissions components in accordance with § 60.5399b. You must submit the notification in paragraph (a)(4) of this section if you undertake well closure activities as specified in § 60.5397b(l).

(1) If you own or operate a process unit equipment affected facility located at an onshore natural gas processing plant, or a sweetening unit, you must submit the notifications required in §§ 60.7(a)(1), (3), and (4) and 60.15(d). If you own or operate a well, centrifugal compressor, reciprocating compressor, process controller, pump, storage vessel, collection of fugitive emissions components at a well site, or collection of fugitive emissions components at a compressor station affected facility, you are not required to submit the notifications required in §§ 60.7(a)(1), (3), and (4) and 60.15(d).

(2) If you own or operate a well affected facility, you must notify the Administrator no later than 2 days prior to the commencement of each well completion operation listing the anticipated date of the well completion operation. The notification shall include contact information for the owner or operator; the United States Well Number; the latitude and longitude coordinates for each well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983; and the planned date of the beginning of flowback. You may submit the notification in writing or in electronic format. If you are subject to state regulations that require advance notification of well completions and you have met those notification requirements, then you are considered to have met the advance notification requirements of this paragraph.

(3) An owner or operator electing to comply with the provisions of § 60.5399b for fugitive emissions components shall notify the Administrator of the alternative fugitive emissions standard selected within the annual report, as specified in paragraph (b)(9)(iii) of this section.

(4) An owner or operator who commences well closure activities must submit the following notices to the Administrator according to the schedule in paragraph (a)(4)(i) and (ii) of this section. The notification shall

include contact information for the owner or operator; the United States Well Number; the latitude and longitude coordinates for each well at the well site in decimal degrees to an accuracy and precision of five

(5) decimals of a degree using the North American Datum of 1983. You must submit notifications in portable document format (PDF) following the procedures specified in paragraph (d) of this section.

(i) You must submit a well closure plan to the Administrator within 30 days of the cessation of production from all wells located at the well site.

(ii) You must submit a notification of the intent to close a well site 60 days before you begin well closure activities.

(b) *Reporting requirements.* You must submit annual reports containing the information specified in paragraphs (b)(1) through (14) of this section following the procedure specified in paragraph (b)(15) of this section. You must submit performance test reports as specified in paragraph (b)(12) or (13) of this section, if applicable. The initial annual report is due no later than 90 days after the end of the initial compliance period as determined according to § 60.5410b. Subsequent annual reports are due no later than the same date each year as the initial annual report. If you own or operate more than one affected facility, you may submit one report for multiple affected facilities provided the report contains all of the information required as specified in paragraphs (b)(1) through (14) 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. You must submit the information in paragraph (b)(1)(v) of this section, as applicable, for your well affected facility which undergoes a change of ownership during the reporting period, regardless of whether reporting under paragraphs (b)(2) through (4) of this section is required for the well affected facility.

(1) The general information specified in paragraphs (b)(1)(i) through (v) of this section is required for all reports.

(i) The company name, facility site name associated with the affected facility, U.S. Well ID or U.S. Well ID associated with the affected facility, if applicable, and address of the affected facility. If an address is not available for the site, include a description of the site location and provide the latitude and longitude coordinates of the site in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(ii) An identification of each affected facility being included in the annual report.

(iii) Beginning and ending dates of the reporting period.

(iv) A certification by a certifying official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. If your report is submitted via CEDRI, the certifier's electronic signature during the submission process replaces the requirement in this paragraph (b)(1)(iv).

(v) Identification of each well affected facility for which ownership changed due to sale or transfer of ownership including the United States Well Number; the latitude and longitude coordinates of the well affected facility in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983; and the information in paragraph (b)(1)(v)(A) or (B) of this section, as applicable.

(A) The name and contact information, including the phone number, email address, and mailing address, of the owner or operator to which you sold or transferred ownership of the well affected facility identified in paragraph (b)(1)(v) of this section.

(B) The name and contact information, including the phone number, email address, and mailing address, of the owner or operator from whom you acquired the well affected facility identified in paragraph (b)(1)(v) of this section.

(2) For each well affected facility that is subject to § 60.5375b(a) or (f), the records of each well completion operation conducted during the reporting period, including the information specified in paragraphs (b)(2)(i) through (xiv) of this section, if applicable. In lieu of submitting the records specified in paragraphs (b)(2)(i) through (xiv) of this section, the owner or operator may submit a list of each well completion with hydraulic fracturing completed during the reporting period, and the digital photograph required by paragraph (c)(1)(v) of this section for each well completion. For each well affected facility that routes all flowback entirely through one or more production separators, only the records specified in paragraphs (b)(2)(i) through (iv) and (vi) of this section are required to be reported. For periods where salable gas is unable to be separated, the records specified in paragraphs (b)(2)(iv) and (viii) through (xii) of this section must also be reported, as applicable. For each well affected facility that is subject to § 60.5375b(g), the record specified in paragraph (b)(2)(xv) of this section is required to be reported. For each well affected facility which makes a claim that the exemption in § 60.5375b(h) was met, the records specified in paragraph (b)(2)(i) through (iv) and (b)(2)(xvi) of this section are required to be reported.

(i) Well Completion ID.

(ii) Latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983.

(iii) U.S. Well ID.

(iv) The date and time of the onset of flowback following hydraulic fracturing or refracturing or identification that the well immediately starts production.

(v) The date and time of each attempt to direct flowback to a separator as required in § 60.5375b(a)(1)(ii).

(vi) The date and time that the well was shut in and the flowback equipment was permanently disconnected, or the startup of production.

(vii) The duration (in hours) of flowback.

(viii) The duration (in hours) of recovery and disposition of recovery (*i.e.*, routed to the gas flow line or collection system, re-injected into the well or another well, used as an onsite fuel source, or used for another useful purpose that a purchased fuel or raw material would serve).

(ix) The duration (in hours) of combustion.

(x) The duration (in hours) of venting.

(xi) The specific reasons for venting in lieu of capture or combustion.

(xii) For any deviations recorded as specified in paragraph (c)(1)(ii) of this section, the date and time the deviation began, the duration of the deviation in hours, and a description of the deviation.

(xiii) For each well affected facility subject to § 60.5375b(f), a record of the well type (*i.e.*, wildcat well, delineation well, or low pressure well (as defined § 60.5430b)) and supporting inputs and calculations, if applicable.

(xiv) For each well affected facility for which you claim an exception under § 60.5375b(a)(2), the specific exception claimed and reasons why the well meets the claimed exception.

(xv) For each well affected facility with less than 300 scf of gas per stock tank barrel of oil produced, the supporting analysis that was performed in order to make that claim, including but not limited to, GOR values for established leases and data from wells in the same basin and field.

(xvi) For each well affected facility which meets the exemption in § 60.5375b(h), a statement that the well completion operation requirements of § 60.5375b(a)(1) through (3) were met.

(3) For each well affected facility that is subject to § 60.5376b(a)(1) or (2), your annual report is required to include the information specified in paragraphs (b)(3)(i) and (ii) of this section, as applicable.

(i) For each well affected facility where all gas well liquids unloading operations comply with § 60.5376b(a)(1), your annual report must include the information specified in paragraphs (b)(3)(i)(A) through (C) of this section, as applicable.

(A) Identification of each well affected facility (U.S. Well ID or U.S. Well ID associated with the well affected facility) that conducts a gas well liquid unloading operation during the reporting period using a method that does not vent to the atmosphere and the technology or technique used. If more than one non-venting technology or technique is used, you must identify all of the differing non-venting liquids unloading methods used during the reporting period.

(B) Number of gas well liquids unloading operations conducted during the year where the well affected facility identified in (b)(3)(i)(A) had unplanned venting to the atmosphere and best management practices were conducted according to your best management practice plan, as required by § 60.5376b(c). If no venting events occurred, the number would be zero. Other reported information required to be submitted where unplanned venting occurs is specified in paragraphs (b)(3)(i)(B)(1) and (2) of this section.

(1) Log of best management practice plan steps used during the unplanned venting to minimize emissions to the maximum extent possible.

(2) The number of liquids unloading events during the year where deviations from your best management practice plan occurred, the date and time the deviation began, the duration of the deviation in hours, documentation of why best management practice plan steps were not followed, and what steps, in lieu of your best management practice plan steps, were followed to minimize emissions to the maximum extent possible.

(C) The number of liquids unloading events where unplanned emissions are vented to the atmosphere during a gas well liquids unloading operation where you complied with best management practices to minimize emissions to the maximum extent possible.

(ii) For each well affected facility where all gas well liquids unloading operations comply with § 60.5376b(b) and (c) best management practices, your annual report must include the information specified in paragraphs (b)(3)(ii)(A) through (E) of this section.

(A) Identification of each well affected facility that conducts a gas well liquids unloading during the reporting period.

(B) Number of liquids unloading events conducted during the reporting period.

(C) Log of best management practice plan steps used during the reporting period to minimize emissions to the maximum extent possible.

(D) The number of liquids unloading events during the year that best management practices were conducted according to your best management practice plan.

(E) The number of liquids unloading events during the year where deviations from your best management practice plan occurred, the date and time the deviation began, the duration of the deviation in hours, documentation of why best management practice plan steps were not followed, and what steps, in lieu of your best management practice plan steps, were followed to minimize emissions to the maximum extent possible.

(4) For each associated gas well subject to § 60.5377b, your annual report is required to include the applicable information specified in paragraphs (b)(4)(i) through (vi) of this section, as applicable.

(i) For each associated gas well that complies with § 60.5377b(a)(1), (2), (3), or (4) your annual report is required to include the information specified in paragraphs (b)(4)(i)(A) and (B) of this section.

(A) An identification of each associated gas well constructed, modified, or reconstructed during the reporting period that complies with § 60.5377b(a)(1), (2), (3), or (4).

(B) The information specified in paragraphs (b)(2)(i)(B)(1) through (3) of this section for each incident when the associated gas was temporarily routed to a flare or control device in accordance with § 60.5377b(d).

(1) The reason in § 60.5377b(d)(1), (2), (3), or (4) for each incident.

(2) The start date and time of each incident of routing associated gas to the flare or control device, along with the total duration in hours of each incident.

(3) Documentation that all CVS requirements specified in § 60.5411b(a) and (c) and all applicable flare or control device requirements specified in § 60.5412b were met during each period when the associated gas is routed to the flare or control device.

(ii) For all instances where you temporarily vent the associated gas in accordance with § 60.5377b(e), you must report the information specified in paragraphs (b)(4)(ii)(A) through (D) of this section. This information is required to be reported if you are routinely complying with § 60.5377b(a) or § 60.5377b(f) or temporarily complying with § 60.5377b(d). In addition to this information for each incident, you must report the cumulative duration in hours of venting incidents and the cumulative VOC and methane emissions in pounds for all incidents in the calendar year.

(A) The reason in § 60.5377b(e)(1), (2), or (3) for each incident.

(B) The start date and time of each incident of venting the associated gas, along with the total duration in hours of each incident.

(C) The VOC and methane emissions in pounds that were emitted during each incident.

(D) The total duration of venting for all incidents in the year, along with the cumulative VOC and methane emissions in pounds that were emitted.

(iii) For each associated gas well that complies with the requirements of § 60.5377b(f) your annual report must include the information specified in paragraphs (b)(4)(iii)(A) through (E) of this section. The information in paragraphs (b)(4)(iii)(A) and (B) of this section is only required in the initial annual report.

(A) An identification of each associated gas well that commenced construction between May 7, 2024, and May 7, 2026. This identification must include the certification of why it is infeasible to comply with § 60.5377b(a)(1), (2), (3), or (4) in accordance with § 60.5377b(g).

(B) An identification of each associated gas well that commenced construction between December 6, 2022, and May 7, 2024. This identification must include the certification of why it is infeasible to comply with § 60.5377b(a)(1), (2), (3), or (4) in accordance with § 60.5377b(g).

(C) An identification of each associated gas well modified or reconstructed during the reporting period that complies by routing the gas to a control device that reduces VOC and methane emissions by at least 95.0 percent. This identification must include the certification of why it is infeasible to comply with § 60.5377b(a)(1), (2), (3), or (4) in accordance with § 60.5377b(g).

(D) For each associated gas well that was constructed, modified or reconstructed in a previous reporting period that complies by routing the gas to a control device that reduces VOC and methane emissions by at least 95.0 percent, a re-certification of why it is infeasible to comply with § 60.5377b(a)(1), (2), (3), or (4) in accordance with § 60.5377b(g).

(E) The information specified in paragraphs (b)(11)(i) through (iv) of this section.

(iv) If you comply with § 60.5377b(f) with a control device, identification of the associated gas well using the control device and the information in paragraph (b)(11)(v) of this section.

(v) If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraphs (b)(11)(i) and (ii) of this section, you must provide the information specified in § 60.5424b.

(vi) For each deviation recorded as specified in paragraph (c)(3)(v) of this section, the date and time the deviation began, the duration of the deviation in hours, and a description of the deviation. If no deviations occurred during the reporting period, you must include a statement that no deviations occurred during the reporting period.

(5) For each wet seal centrifugal compressor affected facility, the information specified in paragraphs (b)(5)(i) through (v) of this section. For each self-contained wet seal centrifugal compressor, Alaska North Slope centrifugal compressor equipped with sour seal oil separator and capture system, or dry seal centrifugal compressor affected facility, the information specified in paragraphs (b)(5)(vi) through (ix) of this section.

(i) An identification of each centrifugal compressor constructed, modified, or reconstructed during the reporting period.

(ii) For each deviation that occurred during the reporting period and recorded as specified in paragraph (c)(4) of this section, the date and time the deviation began, the duration of the deviation in hours, and a description of the deviation. If no deviations occurred during the reporting period, you must include a statement that no deviations occurred during the reporting period.

(iii) If required to comply with § 60.5380b(a)(2) or (3), the information specified in paragraphs (b)(11)(i) through (iv) of this section, as applicable.

(iv) If complying with § 60.5380b(a)(1) with a control device, identification of the centrifugal compressor with the control device and the information in paragraph (b)(11)(v) of this section.

(v) If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraphs (b)(11)(i) and (ii) of this section, you must provide the information specified in § 60.5424b.

(vi) If complying with § 60.5380b(a)(4), (5), or (6) for a self-contained wet seal centrifugal compressor, Alaska North Slope centrifugal compressor equipped with sour seal oil separator and capture system, or dry seal centrifugal compressor requirements, the cumulative number of hours of operation since initial startup, since May 7, 2024, or since the previous volumetric flow rate emissions measurement, as applicable, which have elapsed prior to conducting your volumetric flow rate emission measurement or emissions screening.

(vii) A description of the method used and the results of the volumetric emissions measurement or emissions screening, as applicable.

(viii) Number and type of seals on delay of repair and explanation for each delay of repair.

(ix) Date of planned shutdown(s) that occurred during the reporting period if there are any seals that have been placed on delay of repair.

(6) For each reciprocating compressor affected facility, the information specified in paragraphs (b)(6)(i) through (vii) of this section, as applicable.

(i) The cumulative number of hours of operation since initial startup, since May 7, 2024, since the previous volumetric flow rate measurement, or since the previous reciprocating compressor rod packing replacement, as applicable, which have elapsed prior to conducting your volumetric flow rate measurement or emissions screening. Alternatively, a statement that emissions from the rod packing are being routed to a process or control device through a closed vent system.

(ii) If applicable, for each deviation that occurred during the reporting period and recorded as specified in paragraph (c)(5)(i) of this section, the date and time the deviation began, duration of the deviation in hours and a description of the deviation. If no deviations occurred during the reporting period, you must include a statement that no deviations occurred during the reporting period.

(iii) A description of the method used and the results of the volumetric flow rate measurement or emissions screening, as applicable.

(iv) If complying with § 60.5385b(d)(1) or (2), the information in paragraphs (b)(11)(i) through (iv) of this section. If complying by routing emissions to a control device, as required in § 60.5385b(d)(2), the information in paragraph (b)(11)(v) of this section.

(v) Number and type of rod packing replacements/repairs on delay of repair and explanation for each delay of repair.

(vi) Date of planned shutdown(s) that occurred during the reporting period if there are any rod packing replacements/repairs that have been placed on delay of repair.

(vii) If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraphs (b)(11)(i) and (ii) of this section, you must provide the information specified in § 60.5424b.

(7) For each process controller affected facility, the information specified in paragraphs (b)(7)(i) through (iii) of this section in your initial annual report and in subsequent annual reports for each process controller affected facility that is constructed, modified, or reconstructed during the reporting period. Each annual report must contain the information specified in paragraphs (b)(7)(iv) through (x) of this section for each process controller affected facility.

(i) An identification of each process controller that is driven by natural gas, as required by § 60.5390b(d), that allows traceability to the records required in paragraph (c)(6)(i) of this section.

(ii) For each process controller in the affected facility complying with § 60.5390b(a), you must report the information specified in paragraphs (b)(7)(ii)(A) and (B) of this section, as applicable.

(A) An identification of each process controller complying with § 60.5390b(a) by routing the emissions to a process.

(B) An identification of each process controller complying with § 60.5390b(a) by using a self-contained natural gas-driven process controller.

(iii) For each process controller affected facility located at a site in Alaska that does not have access to electrical power and that complies with § 60.5390b(b), you must report the information specified in paragraphs (b)(7)(iii)(A), (B), or (C) of this section, as applicable.

(A) For each process controller complying with § 60.5390b(b)(1) process controller bleed rate requirements, you must report the information specified in paragraphs (b)(7)(iii)(A)(1) and (2) of this section.

(1) The identification of process controllers designed and operated to achieve a bleed rate less than or equal to 6 scfh.

(2) Where necessary to meet a functional need, the identification and demonstration why it is necessary to use a process controller with a natural gas bleed rate greater than 6 scfh.

(B) An identification of each intermittent vent process controller complying with the requirements in paragraph § 60.5390b(b)(2).

(C) An identification of each process controller complying with the requirements in § 60.5390b(b) by routing emissions to a control device in accordance with § 60.5390b(b)(3).

(iv) Identification of each process controller which changes its method of compliance during the reporting period and the applicable information specified in paragraphs (b)(7)(v) through (ix) of this section for the new method of compliance.

(v) For each process controller in the affected facility complying with the requirements of § 60.5390b(a) by routing the emissions to a process, you must report the information specified in (b)(11)(i) through (iii) of this section.

(vi) For each process controller in the affected facility complying with the requirements of § 60.5390b(a) by using a self-contained natural gas-driven process controller, you must report the information specified in paragraphs (b)(7)(vi)(A) and (B) of this section.

(A) Dates of each inspection required under § 60.5416b(b); and

(B) Each defect or leak identified during each natural gas-driven-self-contained process controller system inspection, and the date of repair or date of anticipated repair if repair is delayed.

(vii) For each process controller in the affected facility complying with the requirements of § 60.5390b(b)(2), you must report the information specified in paragraphs (b)(7)(vii)(A) and (B) of this section.

(A) Dates and results of the intermittent vent process controller monitoring required by § 60.5390b(b)(2)(ii).

(B) For each instance in which monitoring identifies emissions to the atmosphere from an intermittent vent controller during idle periods, the date of repair or replacement or the date of anticipated repair or replacement if the repair or replacement is delayed, and the date and results of the re-survey after repair or replacement.

(viii) For each process controller affected facility complying with § 60.5390b(b)(3) by routing emissions to a control device, you must report the information specified in paragraph (b)(11) of this section.

(ix) For each deviation that occurred during the reporting period, the date and time the deviation began, the duration of the deviation in hours, and a description of the deviation. If no deviations occurred

during the reporting period, you must include a statement that no deviations occurred during the reporting period.

(x) If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraphs (b)(7)(vi) and (vii) and (b)(11)(i) and (ii) of this section, you must provide the information specified in § 60.5424b.

(8) For each storage vessel affected facility, the information in paragraphs (b)(8)(i) through (x) of this section.

(i) An identification, including the location, of each storage vessel affected facility, including those for which construction, modification, or reconstruction commenced during the reporting period, and those provided in previous reports. The location of the storage vessel affected facility 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 methane and VOC emission rate determination according to § 60.5365b(e)(1) for each tank battery that became an affected facility during the reporting period or is returned to service during the reporting period.

(iii) For each deviation that occurred during the reporting period and recorded as specified in paragraph (c)(7)(iii) of this section, the date and time the deviation began, duration of the deviation in hours and a description of the deviation. If no deviations occurred during the reporting period, you must include a statement that no deviations occurred during the reporting period.

(iv) For each storage vessel affected facility constructed, modified, reconstructed, or returned to service during the reporting period complying with § 60.5395b(a)(2) with a control device, report the identification of the storage vessel affected facility with the control device and the information in paragraph (b)(11)(v) of this section.

(v) If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraphs (b)(11)(i) and (ii) of this section, you must provide the information specified in § 60.5424b.

(vi) If required to comply with § 60.5395b(b)(1), the information in paragraphs (b)(11)(i) through (iv) of this section.

(vii) You must identify each storage vessel affected facility that is removed from service during the reporting period as specified in § 60.5395b(c)(1)(ii), including the date the storage vessel affected facility was removed from service. You must identify each storage vessel that that is removed from service from a storage vessel affected facility during the reporting period as specified in § 60.5395b(c)(2)(iii), including identifying the impacted storage vessel affected facility and the date each storage vessel was removed from service.

(viii) You must identify each storage vessel affected facility or portion of a storage vessel affected facility returned to service during the reporting period as specified in § 60.5395b(c)(4), including the date the storage vessel affected facility or portion of a storage vessel affected facility was returned to service.

(ix) You must identify each storage vessel affected facility that no longer complies with § 60.5395b(a)(3) and instead complies with § 60.5395b(a)(2). You must identify whether the change in the method of compliance was due to fracturing or refracturing or whether the change was due to an increase in the monthly emissions determination. If the change was due to an increase in the monthly emissions determination, you must provide documentation of the emissions rate. You must identify the date that you complied with § 60.5395b(a)(2) and must submit the information in (b)(8)(iii) through (vii) of this section.

(x) You must submit a statement that you are complying with § 60.112b(a)(1) or (2), if applicable, in your initial annual report.

(9) For the fugitive emissions components affected facility, report the information specified in paragraphs (b)(9)(i) through (v) of this section, as applicable.

(i)

(A) Designation of the type of site (*i.e.*, well site, centralized production facility, or compressor station) at which the fugitive emissions components affected facility is located.

(B) For the fugitive emissions components affected facility at a well site or centralized production facility that became an affected facility during the reporting period, you must include the date of the startup of production or the date of the first day of production after modification. For the fugitive emissions components affected facility at a compressor station that became an affected facility during the reporting period, you must include the date of startup or the date of modification.

(C) For the fugitive emissions components affected facility at a well site, you must specify what type of well site it is (*i.e.*, single wellhead only well site, small wellsite, multi-wellhead only well site, or a well site with major production and processing equipment).

(D) For the fugitive emissions components affected facility at a well site where during the reporting period you complete the removal of all major production and processing equipment such that the well site contains only one or more wellheads, you must include the date of the change to status as a wellhead only well site.

(E) For the fugitive emissions components affected facility at a well site where you previously reported under paragraph (b)(9)(i)(D) of this section the removal of all major production and processing equipment and during the reporting period major production and processing equipment is added back to the well site, the date that the first piece of major production and processing equipment is added back to the well site.

(F) For the fugitive emissions components affected facility at a well site where during the reporting period you undertake well closure requirements, the date of the cessation of production from all wells at the well site, the date you began well closure activities at the well site, and the dates of the notifications submitted in accordance with paragraph (a)(4) of this section.

(ii) For each fugitive emissions monitoring survey performed during the annual reporting period, the information specified in paragraphs (b)(9)(ii)(A) through (G) of this section.

(A) Date of the survey.

(B) Monitoring instrument or, if the survey was conducted by AVO methods, notation that AVO was used.

(C) Any deviations from the monitoring plan elements under § 60.5397b(c)(1), (2), and (7), (c)(8)(i), or (d) or a statement that there were no deviations from these elements of the monitoring plan.

(D) Number and type of components for which fugitive emissions were detected.

(E) Number and type of fugitive emissions components that were not repaired as required in § 60.5397b(h).

(F) Number and type of fugitive emission components (including designation as difficult-to-monitor or unsafe-to-monitor, if applicable) on delay of repair and explanation for each delay of repair.

(G) Date of planned shutdown(s) that occurred during the reporting period if there are any components that have been placed on delay of repair.

(iii) For the fugitive emissions components affected facility complying with an alternative fugitive emissions standard under § 60.5399b, in lieu of the information specified in paragraphs (b)(9)(i) and (ii) of this section, you must provide the information specified in paragraphs (b)(9)(iii)(A) through (C) of this section.

(A) The alternative standard with which you are complying.

(B) The site-specific reports specified by the specific alternative fugitive emissions standard, submitted in the format in which they were submitted to the state, local, or Tribal authority. If the report is in hard copy, you must scan the document and submit it as an electronic attachment to the annual report required in paragraph (b) of this section.

(C) If the report specified by the specific alternative fugitive emissions standard is not site-specific, you must submit the information specified in paragraphs (b)(9)(i) and (ii) of this section for each individual site complying with the alternative standard.

(iv) For well closure activities which occurred during the reporting period, the information in paragraphs (b)(9)(iv)(A) and (B) of this section.

(A) A status report with dates for the well closure activities schedule developed in the well closure plan. If all steps in the well closure plan are completed in the reporting period, the date that all activities are completed.

(B) If an OGI survey is conducted during the reporting period, the information in paragraphs (b)(9)(iv)(B)(1) through (3) of this section.

(1) Date of the OGI survey.

(2) Monitoring instrument used.

(3) A statement that no fugitive emissions were found, or if fugitive emissions were found, a description of the steps taken to eliminate those emissions, the date of the resurvey, the results of the resurvey, and the date of the final resurvey which detected no emissions.

(v) If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraphs (b)(9)(i) and (ii) of this section, you must provide the information specified in § 60.5424b.

(10) For each pump affected facility, the information specified in paragraphs (b)(10)(i) through (iv) of this section in your initial annual report and in subsequent annual reports for each pump affected facility that is constructed, modified, or reconstructed during the reporting period. Each annual report must contain the information specified in paragraphs (b)(10)(v) through (ix) of this section for each pump affected facility.

(i) The identification of each of your pumps that are driven by natural gas, as required by § 60.5393b(a) that allows traceability to the records required by paragraph (c)(15)(i) of this section.

(ii) For each pump affected facility for which there is a control device on site but it does not achieve a 95.0 percent emissions reduction, the certification that there is a control device available on site but it

does not achieve a 95.0 percent emissions reduction required under § 60.5393b(b)(5). You must also report the emissions reduction percentage the control device is designed to achieve.

(iii) For each pump affected facility for which there is no control device or vapor recovery unit on site, the certification required under § 60.5393b(b)(6) that there is no control device or vapor recovery unit on site.

(iv) For each pump affected facility for which it is technically infeasible to route the emissions to a process or control device, the certification of technical infeasibility required under § 60.5393b(b)(7).

(v) For any pump affected facility which has previously reported as required under paragraph (b)(10)(i) through (iv) of this section and for which a change in the reported condition has occurred during the reporting period, provide the identification of the pump affected facility and the date that the pump affected facility meets one of the change conditions described in paragraphs (b)(10)(v)(A), (B), or (C) of this section.

(A) If you install a control device or vapor recovery unit, you must report that a control device or vapor recovery unit has been added to the site and that the pump affected facility now is required to comply with § 60.5393b(b)(2), (3) or (5), as applicable.

(B) If your pump affected facility previously complied with § 60.5393b(b)(2), (3) or (5) by routing emissions to a process or a control device and the process or control device is subsequently removed from the site or is no longer available such that there is no ability to route the emissions to a process or control device at the site, or that it is not technically feasible to capture and route the emissions to another control device or process located on site, report that you are no longer complying with the applicable requirements of § 60.5393b(b)(2), (3), or (5) and submit the information provided in paragraphs (b)(10)(v)(B)(1) or (2) of this section.

(1) Certification that there is no control device or vapor recovery unit on site.

(2) Certification of the engineering assessment that it is technically infeasible to capture and route the emissions to another control device or process located on site.

(C) If any pump affected facility or individual natural gas-driven pump changes its method of compliance during the reporting period other than for the reasons specified in paragraphs (10)(v)(A) and (B) of this section, identify the new compliance method for each natural gas-driven pump within the affected facility which changes its method of compliance during the reporting period and provide the applicable information specified in paragraphs (b)(10)(ii) through (iv) and (vi) through (viii) of this section for the new method of compliance.

(vi) For each pump affected facility complying with the requirements of § 60.5393b(a), (b)(1), or (b)(3) by routing the emissions to a process, you must report the information specified in paragraphs (b)(11)(i) through (iv) of this section.

(vii) For each pump affected facility complying with the requirements of § 60.5393b(b)(3) or (5) by routing the emissions to a control device, you must report the information required under paragraphs (b)(11)(i) through (v) of this section.

(viii) For each deviation that occurred during the reporting period, the date and time the deviation began, the duration of the deviation in hours, and a description of the deviation. If no deviations occurred during the reporting period, you must include a statement that no deviations occurred during the reporting period.

(ix) If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraphs (b)(11)(i) and (ii) of this section, you must provide the information specified in § 60.5424b.

(11) For each well, centrifugal compressor, reciprocating compressor, storage vessel, process controller, pump, or process unit equipment affected facility which uses a closed vent system routed to a control device to meet the emissions reduction standard, you must submit the information in paragraphs (b)(11)(i) through (v) of this section. For each reciprocating compressor, process controller, pump, storage vessel, or process unit equipment which uses a closed vent system to route to a process, you must submit the information in paragraphs (b)(11)(i) through (iv) of this section. For each centrifugal compressor, reciprocating compressor, and storage vessel equipped with a cover, you must submit the information in paragraphs (b)(11)(i) and (ii) of this section.

(i) Dates of each inspection required under § 60.5416b(a) and (b).

(ii) Each defect or emissions identified during each inspection and the date of repair or the date of anticipated repair if the repair is delayed.

(iii) Date and time of each bypass alarm or each instance the key is checked out if you are subject to the bypass requirements of § 60.5416b(a)(4).

(iv) You must submit the certification signed by the qualified professional engineer or in-house engineer according to § 60.5411b(c) for each closed vent system routing to a control device or process in the reporting year in which the certification is signed.

(v) If you comply with the emissions standard for your well, centrifugal compressor, reciprocating compressor, storage vessel, process controller, pump, or process unit equipment affected facility with a control device, the information in paragraphs (b)(11)(v)(A) through (L) of this section, unless you use an enclosed combustion device or flare using an alternative test method approved under § 60.5412b(d). If you use an enclosed combustion device or flare using an alternative test method approved under § 60.5412b(d), the information in paragraphs (b)(11)(v)(A) through (C) and (L) through (P) of this section.

(A) Identification of the control device.

(B) Make, model, and date of installation of the control device.

(C) Identification of the affected facility controlled by the device.

(D) For each continuous parameter monitoring system used to demonstrate compliance for the control device, a unique continuous parameter monitoring system identifier and the make, model number, and date of last calibration check of the continuous parameter monitoring system.

(E) For each instance where there is a deviation of the control device in accordance with § 60.5417b(g)(1) through (3) or (g)(5) through (7) include the date and time the deviation began, the duration of the deviation in hours, the type of the deviation (*e.g.*, NHV operating limit, lack of pilot or combustion flame, condenser efficiency, bypass line flow, visible emissions), and cause of the deviation.

(F) For each instance where there is a deviation of the continuous parameter monitoring system in accordance with § 60.5417b(g)(4) include the date and time the deviation began, the duration of the deviation in hours, and cause of the deviation.

(G) For each visible emissions test following return to operation from a maintenance or repair activity, the date of the visible emissions test or observation of the video surveillance output,

the length of the observation in minutes, and the number of minutes for which visible emissions were present.

(H) If a performance test was conducted on the control device during the reporting period, provide the date the performance test was conducted. Submit the performance test report following the procedures specified in paragraph (b)(12) of this section.

(I) If a demonstration of the NHV of the inlet gas to the enclosed combustion device or flare was conducted during the reporting period in accordance with § 60.5417b(d)(8)(iii), an indication of whether this is a re-evaluation of vent gas NHV and the reason for the re-evaluation; the applicable required minimum vent gas NHV; if twice daily samples of the vent stream were taken, the number of hourly average NHV values that are less than 1.2 times the applicable required minimum NHV; if continuous NHV sampling of the vent stream was conducted, the number of hourly average NHV values that are less than the required minimum vent gas NHV; if continuous combustion efficiency monitoring was conducted using an alternative test method approved under § 60.5412b(d), the number of values of the combustion efficiency that were less than 95.0 percent; the resulting determination of whether NHV monitoring is required or not in accordance with § 60.5417b(d)(8)(iii)(D) or (H); and an indication of whether the enclosed combustion device or flare has the potential to receive inert gases, and if so, whether the sampling included periods where the highest percentage of inert gases were sent to the enclosed combustion device or flare.

(J) If a demonstration was conducted in accordance with § 60.5417b(d)(8)(iv) that the maximum potential pressure of units manifolded to an enclosed combustion device or flare cannot cause the maximum inlet flow rate established in accordance with § 60.5417b(f)(1) or a flare tip velocity limit of 18.3 meter/second (60 feet/second) to be exceeded, an indication of whether this is a re-evaluation of the gas flow and the reason for the re-evaluation; the demonstration conducted; and applicable engineering calculations.

(K) For each periodic sampling event conducted under § 60.5417b(d)(8)(iii)(G), provide the date of the sampling, the required minimum vent gas NHV, and the NHV value for each vent gas sample.

(L) For each flare and enclosed combustion device, provide the date each device is observed with OGI in accordance with § 60.5415b(f)(1)(x) and whether uncombusted emissions were present. Provide the date each device was visibly observed during an AVO inspection in accordance with § 60.5415b(f)(1)(x), whether the pilot or combustion flame was lit at the time of observation, and whether the device was found to be operating properly.

(M) An identification of the alternative test method used.

(N) For each instance where there is a deviation of the control device in accordance with § 60.5417b(i)(6)(i) or (iii) through (v) include the date and time the deviation began, the duration of the deviation in hours, the type of the deviation (*e.g.*, NHV_{cz} operating limit, lack of pilot or combustion flame, visible emissions), and cause of the deviation.

(O) For each instance where there is a deviation of the data availability in accordance with § 60.5417b(i)(6)(ii) include the date of each operating day when monitoring data are not available for at least 75 percent of the operating hours.

(P) If no deviations occurred under paragraphs (b)(11)(v)(N) or (O) of this section, a statement that there were no deviations for the control device during the annual report period.

(Q) Any additional information required to be reported as specified by the Administrator as part of the alternative test method approval under § 60.5412b(d).

(12) Within 60 days after the date of completing each performance test (see § 60.8) required by this subpart, except testing conducted by the manufacturer as specified in § 60.5413b(d), you must submit the results of the performance test following the procedures specified in paragraph (d) of this section. Data collected using test methods that are supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT website (<https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert>) at the time of the test must be submitted in a file format generated using the EPA's ERT. Alternatively, you may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website. Data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test must be included as an attachment in the ERT or alternate electronic file.

(13) For combustion control devices tested by the manufacturer in accordance with § 60.5413b(d), an electronic copy of the performance test results required by § 60.5413b(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 website: <https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry>.

(14) If you had a super-emitter event during the reporting period, the start date of the super-emitter event, the duration of the super-emitter event in hours, and the affected facility associated with the super-emitter event, if applicable.

(15) You must submit your annual report using the appropriate electronic report template on the Compliance and Emissions Data Reporting Interface (CEDRI) website for this subpart and following the procedure specified in paragraph (d) of this section. If the reporting form specific to this subpart is not available on the CEDRI website at the time that the report is due, you must submit the report to the Administrator at the appropriate address listed in § 60.4. Once the form has been available on the CEDRI website for at least 90 calendar days, you must begin submitting all subsequent reports via CEDRI. The date reporting forms become available will be listed on the CEDRI website. Unless the Administrator or delegated state agency or other authority has approved a different schedule for submission of reports, the report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted.

(c) *Recordkeeping requirements.* You must maintain the records identified as specified in § 60.7(f) and in paragraphs (c)(1) through (15) 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. Any records required to be maintained by this subpart that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to a delegated air agency or the EPA as part of an on-site compliance evaluation.

(1) The records for each well affected facility subject to the well completion operation standards of § 60.5375b, as specified in paragraphs (c)(1)(i) through (vii) of this section, as applicable. For each well affected facility subject to the well completion operations of § 60.5375b, for which you make a claim that the well affected facility is not subject to the requirements for well completions pursuant to § 60.5375b(g), you must maintain the record in paragraph (c)(1)(vi) of this section, only. For each well affected facility which meets the exemption in § 60.5375b(h) for well completion operations (*i.e.*, an existing well is hydraulically refractured), you must maintain the records in paragraph (c)(1)(viii), only. For each well affected facility that routes flowback entirely through one or more production separators that are designed to accommodate flowback, only records of the United States Well Number, the latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983, the Well Completion ID, and the date and time of startup of production are required. For periods where salable gas is unable to be separated, records of

the date and time of onset of flowback, the duration and disposition of recovery, the duration of combustion and venting (if applicable), reasons for venting (if applicable), and deviations are required.

- (i) Records identifying each well completion operation for each well affected facility.
- (ii) Records of deviations in cases where well completion operations with hydraulic fracturing were not performed in compliance with the requirements specified in § 60.5375b, including the date and time the deviation began, the duration of the deviation, and a description of the deviation.
- (iii) You must maintain the records specified in paragraphs (c)(1)(iii)(A) through (C) of this section.

(A) For each well affected facility required to comply with the requirements of § 60.5375b(a), you must record: The latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983; the United States Well Number; the date and time of the onset of flowback following hydraulic fracturing or refracturing; the date and time of each attempt to direct flowback to a separator as required in § 60.5375b(a)(1)(ii); the date and time of each occurrence of returning to the initial flowback stage under § 60.5375b(a)(1)(i); and the date and time that the well was shut in and the flowback equipment was permanently disconnected, or the startup of production; the duration of flowback; duration of recovery and disposition of recovery (*i.e.*, routed to the gas flow line or collection system, re-injected into the well or another well, used as an onsite fuel source, or used for another useful purpose that a purchased fuel or raw material would serve); duration of combustion; duration of venting; and specific reasons for venting in lieu of capture or combustion. The duration must be specified in hours. In addition, for wells where it is technically infeasible to route the recovered gas as specified in § 60.5375b(a)(1)(ii), you must record the reasons for the claim of technical infeasibility with respect to all four options provided in § 60.5375b(a)(1)(ii).

(B) For each well affected facility required to comply with the requirements of § 60.5375b(f), you must record: Latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983; the United States Well Number; the date and time of the onset of flowback following hydraulic fracturing or refracturing; the date and time that the well was shut in and the flowback equipment was permanently disconnected, or the startup of production; the duration of flowback; duration of combustion; duration of venting; and specific reasons for venting in lieu combustion. The duration must be specified in hours.

(C) For each well affected facility for which you make a claim that it meets the criteria of § 60.5375b(a)(1)(iii)(A), you must maintain the following:

(1) The latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983; the United States Well Number; the date and time of the onset of flowback following hydraulic fracturing or refracturing; the date and time that the well was shut in and the flowback equipment was permanently disconnected, or the startup of production; the duration of flowback; duration of recovery and disposition of recovery (*i.e.*, routed to the gas flow line or collection system, re-injected into the well or another well, used as an onsite fuel source, or used for another useful purpose that a purchased fuel or raw material would serve); duration of combustion; duration of venting; and specific reasons for venting in lieu of capture or combustion. The duration must be specified in hours.

(2) If applicable, records that the conditions of § 60.5375b(a)(1)(iii)(A) are no longer met and that the well completion operation has been stopped and a separator installed. The records shall include the date and time the well completion operation was stopped and the date and time the separator was installed.

(3) A record of the claim signed by the certifying official that no liquids collection is at the well site. The claim must include a certification by a certifying official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

(iv) For each well affected facility for which you claim an exception under § 60.5375b(a)(2), you must record: The latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983; the United States Well Number; the specific exception claimed; the starting date and ending date for the period the well operated under the exception; and an explanation of why the well meets the claimed exception.

(v) For each well affected facility required to comply with both § 60.5375b(a)(1) and (2), 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 § 60.5410b(a)(4).

(vi) For each well affected facility for which you make a claim that the well affected facility is not subject to the well completion standards according to § 60.5375b(g), you must maintain:

(A) A record of the analysis that was performed in order to make that claim, including but not limited to, GOR values for established leases and data from wells in the same basin and field;

(B) The latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983; the United States Well Number;

(C) A record of the claim signed by the certifying official. The claim must include a certification by a certifying official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

(vii) For each well affected facility subject to § 60.5375b(f), a record of the well type (*i.e.*, wildcat well, delineation well, or low pressure well (as defined § 60.5430b)) and supporting inputs and calculations, if applicable.

(viii) For each well affected facility which makes a claim it meets the exemption at § 60.5375b(h), a record of the latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983; the United States Well Number; the date and time of the onset of flowback following hydraulic fracturing or refracturing and a record of the claim that the well completion operation requirements of § 60.5375b(a)(1) through (3) were met.

(2) For each gas well liquids unloading operation at your well affected facility that is subject to § 60.5376b(a)(1) or (2), the records of each gas well liquids unloading operation conducted during the reporting period, including the information specified in paragraphs (c)(2)(i) through (iii) of this section, as applicable.

(i) For each gas well liquids unloading operation that complies with § 60.5376b(a)(1) by performing all liquids unloading events without venting of methane and VOC emissions to the atmosphere, comply with the recordkeeping requirements specified in paragraphs (c)(2)(i)(A) and (B) of this section.

(A) Identification of each well (*i.e.*, U.S. Well ID or U.S. Well ID associated with the well affected facility) that conducts a gas well liquids unloading operation during the reporting period without venting of methane and VOC emissions and the non-venting methane and VOC gas well liquids unloading method used. If more than one non-venting method is used, you must maintain records of all the differing non-venting liquids unloading methods used at the well affected facility complying with § 60.5376b(a)(1).

(B) Number of events where unplanned emissions are vented to the atmosphere during a gas well liquids unloading operation where you complied with best management practices to minimize emissions to the maximum extent possible.

(ii) For each gas well liquids unloading operation that complies with § 60.5376b(b) and (c) best management practices, maintain records documenting information specified in paragraphs (c)(2)(ii)(A) through (D) of this section.

(A) Identification of each well affected facility that conducts liquids unloading during the reporting period that employs best management practices to minimize emissions to the maximum extent possible.

(B) Documentation of your best management practice plan developed under paragraph § 60.5376b(c). You may update your best management practice plan to include additional steps which meet the criteria in § 60.5376b(c).

(C) A log of each best management practice plan step taken to minimize emissions to the maximum extent possible for each gas well liquids unloading event.

(D) Documentation of each gas well liquids unloading event where deviations from your best management practice plan steps occurred, the date and time the deviation began, the duration of the deviation, documentation of best management practice plan steps not followed, and the steps taken in lieu of your best management practice plan steps during those events to minimize emissions to the maximum extent possible.

(iii) For each well affected facility that reduces methane and VOC emissions from well affected facility gas wells that unload liquids by 95.0 percent by routing emissions to a control device through closed vent system under § 60.5376b(g), you must maintain the records in paragraphs (c)(2)(iii)(A) through (E) of this section.

(A) If you comply with the emission reduction standard with a control device, the information for each control device in paragraph (c)(11) of this section.

(B) Records of the closed vent system inspection as specified paragraph (c)(8) of this section.

(C) Records of the cover inspections as specified in paragraph (c)(9) of this section.

(D) If applicable, the records of bypass monitoring as specified in paragraph (c)(10) of this section.

(E) Records of the closed vent system assessment as specified in paragraph (c)(12) of this section.

(3) For each associated gas well, you must maintain the applicable records specified in paragraphs (c)(3)(i) or (ii) and (c)(3)(iv) of this section.

(i) For each associated gas well that complies with the requirements of § 60.5377b(a)(1), (2), (3), or (4), you must keep the records specified in paragraphs (c)(3)(i)(A) and (B).

(A) Documentation of the specific method(s) in § 60.5377b(a)(1), (2), (3), or (4) that is used.

(B) For instances where you temporarily route the associated gas to a flare or control device in accordance with § 60.5377b(d), you must keep the records specified in paragraphs (c)(3)(i)(B)(1) through (3).

(1) The reason in § 60.5377b(d)(1), (2), (3), or (4) for each incident.

(2) The date of each incident, along with the times when routing the associated gas to the flare or control device started and ended, along with the total duration of each incident.

(3) Documentation that all CVS requirements specified in § 60.5411b(a) and (c) and all applicable flare or control device requirements specified in § 60.5412b are met during each period when the associated gas is routed to the flare or control device.

(ii) For instances where you temporarily vent the associated gas in accordance with § 60.5377b(e), you must keep the records specified in paragraphs (c)(3)(ii)(A) through (D). These records are required if you are routinely complying with § 60.5377b(a) or § 60.5377b(f) or temporarily complying with § 60.5377b(d).

(A) The reason in § 60.5377b(e)(1), (2), or (3) for each incident.

(B) The date of each incident, along with the times when venting the associated gas started and ended, along with the total duration of each incident.

(C) The VOC and methane emissions that were emitted during each incident.

(D) The cumulative duration of venting incidents and VOC and methane emissions for all incidents in each calendar year.

(iii) For each associated gas well that complies with the requirements of § 60.5377b(f) because it has demonstrated that it is not feasible to comply with § 60.5377b(a)(1), (2), (3), and (4) due to technical reasons in accordance with § 60.5377b(g), records of each annual demonstration and certification of the technical reason that it is not feasible to comply with § 60.5377b(a)(1), (2), (3), and (4) in accordance with § 60.5377b(g).

(iv) For each associated gas well that complies with the requirements of § 60.5377b(f), meet the recordkeeping requirements specified in paragraphs (c)(3)(iv)(A) through (E).

(A) Identification of each instance when associated gas was vented and not routed to a control device that reduces VOC and methane emissions by at least 95.0 percent.

(B) If you comply with the emission reduction standard in § 60.5377b with a control device, the information for each control device in paragraphs (c)(11) and (13) of this section.

(C) Records of the closed vent system inspection as specified paragraph (c)(8) of this section. If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraph (c)(8) of this section, you must maintain records of the information specified in § 60.5424b.

(D) If applicable, the records of bypass monitoring as specified in paragraph (c)(10) of this section.

(E) Records of the closed vent system assessment as specified in paragraph (c)(12) of this section.

(v) Records of each deviation, the date and time the deviation began, the duration of the deviation, and a description of the deviation.

(4) For each centrifugal compressor affected facility, you must maintain the records specified in paragraphs (c)(4)(i) through (iii) of this section.

(i) For each centrifugal compressor affected facility, you must maintain records of deviations in cases where the centrifugal compressor was not operated in compliance with the requirements specified in § 60.5380b, including a description of each deviation, the date and time each deviation began and the duration of each deviation.

(ii) For each wet seal compressor complying with the emissions reduction standard in § 60.5380b(a)(1), you must maintain the records in paragraphs (c)(4)(ii)(A) through (E) of this section. For each wet seal compressor complying with the alternative standard in § 60.5380b(a)(3) by routing the closed vent system to a process, you must maintain the records in paragraphs (c)(4)(ii)(B) through (E) of this section.

(A) If you comply with the emission reduction standard in § 60.5380b(a)(1) with a control device, the information for each control device in paragraph (c)(11) of this section.

(B) Records of the closed vent system inspection as specified paragraph (c)(8) of this section. If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraph (c)(8) of this section, you must maintain the information specified in § 60.5424b.

(C) Records of the cover inspections as specified in paragraph (c)(9) of this section. If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraphs (c)(9) of this section, you must maintain the information specified in § 60.5424b.

(D) If applicable, the records of bypass monitoring as specified in paragraph (c)(10) of this section.

(E) Records of the closed vent system assessment as specified in paragraph (c)(12) of this section.

(iii) For each centrifugal compressor affected facility using a self-contained wet seal compressor, centrifugal compressor equipped with sour seal oil separator and capture system, or dry seal compressor complying with the standard in § 60.5380b(a)(4), (5) or (6), you must maintain the records specified in paragraphs (c)(4)(iii)(A) through (H) of this section.

(A) Records of the cumulative number of hours of operation since initial startup, since May 7, 2024, or since the previous volumetric flow rate measurement, as applicable.

(B) A description of the method used and the results of the volumetric flow rate measurement or emissions screening, as applicable.

(C) Records for all flow meters, composition analyzers and pressure gauges used to measure volumetric flow rates as specified in paragraphs (c)(4)(iii)(C)(1) through (6).

(1) Description of standard method published by a consensus-based standards organization or industry standard practice.

(2) Records of volumetric flow rate emissions calculations conducted according to paragraphs § 60.5380b(a)(4) through (6), as applicable.

(3) Records of manufacturer's operating procedures and measurement methods.

(4) Records of manufacturer's recommended procedures or an appropriate industry consensus standard method for calibration and results of calibration, recalibration, and accuracy checks.

(5) Records which demonstrate that measurements at the remote location(s) can, when appropriate correction factors are applied, reliably and accurately represent the actual temperature or total pressure at the flow meter under all expected ambient conditions. You must include the date of the demonstration, the data from the demonstration, the mathematical correlation(s) between the remote readings and actual flow meter conditions derived from the data, and any supporting engineering calculations. If adjustments were made to the mathematical relationships, a record and description of such adjustments.

(6) Record of each initial calibration or a recalibration which failed to meet the required accuracy specification and the date of the successful recalibration.

(D) Date when performance-based volumetric flow rate is exceeded.

(E) The date of successful repair of the compressor seal, including follow-up performance-based volumetric flow rate measurement to confirm successful repair.

(F) Identification of each compressor seal placed on delay of repair and explanation for each delay of repair.

(G) For each compressor seal or part needed for repair placed on delay of repair because of replacement seal or part unavailability, the operator must document: the date the seal or part was added to the delay of repair list, the date the replacement seal or part was ordered, the anticipated seal or part delivery date (including any estimated shipment or delivery date provided by the vendor), and the actual arrival date of the seal or part.

(H) Date of planned shutdowns that occur while there are any seals or parts that have been placed on delay of repair.

(5) For each reciprocating compressor affected facility, you must maintain the records in paragraphs (c)(5)(i) through (x) and (c)(8) through (13) of this section, as applicable. If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraph (c)(8) of this section, you must provide the information specified in § 60.5424b.

(i) For each reciprocating compressor affected facility, you must maintain records of deviations in cases where the reciprocating compressor was not operated in compliance with the requirements specified in § 60.5385b, including a description of each deviation, the date and time each deviation began and the duration of each deviation in hours.

(ii) Records of the date of installation of a rod packing emissions collection system and closed vent system as specified in § 60.5385b(d).

(iii) Records of the cumulative number of hours of operation since initial startup, since May 7, 2024, or since the previous volumetric flow rate measurement, as applicable. Alternatively, a record that emissions from the rod packing are being routed to a process through a closed vent system.

(iv) A description of the method used and the results of the volumetric flow rate measurement or emissions screening, as applicable.

(v) Records for all flow meters, composition analyzers and pressure gauges used to measure volumetric flow rates as specified in paragraphs (c)(5)(v)(A) through (F).

(A) Description of standard method published by a consensus-based standards organization or industry standard practice.

(B) Records of volumetric flow rate calculations conducted according to paragraphs § 60.5385b(b) or (c), as applicable.

(C) Records of manufacturer operating procedures and measurement methods.

(D) Records of manufacturer's recommended procedures or an appropriate industry consensus standard method for calibration and results of calibration, recalibration, and accuracy checks.

(E) Records which demonstrate that measurements at the remote location(s) can, when appropriate correction factors are applied, reliably and accurately represent the actual temperature or total pressure at the flow meter under all expected ambient conditions. You must include the date of the demonstration, the data from the demonstration, the mathematical correlation(s) between the remote readings and actual flow meter conditions derived from the data, and any supporting engineering calculations. If adjustments were made to the mathematical relationships, a record and description of such adjustments.

(F) Record of each initial calibration or a recalibration which failed to meet the required accuracy specification and the date of the successful recalibration.

(vi) Date when performance-based volumetric flow rate is exceeded.

(vii) The date of successful replacement or repair of reciprocating compressor rod packing, including follow-up performance-based volumetric flow rate measurement to confirm successful repair.

(viii) Identification of each reciprocating compressor placed on delay of repair because of rod packing or part unavailability and explanation for each delay of repair.

(ix) For each reciprocating compressor that is placed on delay of repair because of replacement rod packing or part unavailability, the operator must document: the date the rod packing or part was added to the delay of repair list, the date the replacement rod packing or part was ordered, the anticipated rod packing or part delivery date (including any estimated shipment or delivery date provided by the vendor), and the actual arrival date of the rod packing or part.

(x) Date of planned shutdowns that occur while there are any reciprocating compressors that have been placed on delay of repair due to the unavailability of rod packing or parts to conduct repairs.

(6) For each process controller affected facility, you must maintain the records specified in paragraphs (c)(6)(i) through (vii) of this section.

(i) Records identifying each process controller that is driven by natural gas and that does not function as an emergency shutdown device.

(ii) For each process controller affected facility complying with § 60.5390b(a), you must maintain records of the information specified in paragraphs (c)(6)(ii)(A) and (B) of this section, as applicable.

(A) If you are complying with § 60.5390b(a) by routing process controller vapors to a process through a closed vent system, you must report the information specified in paragraphs (c)(6)(ii)(A)(1) and (2) of this section.

(1) An identification of all the natural gas-driven process controllers in the process controller affected facility for which you collect and route vapors to a process through a closed vent system.

(2) The records specified in paragraphs (c)(8), (10), and (12) of this section. If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraph (c)(8) of this section, you must provide the information specified in § 60.5424b.

(B) If you are complying with § 60.5390b(a) by using a self-contained natural gas-driven process controller, you must report the information specified in paragraphs (c)(6)(ii)(B)(1) through (3) of this section.

(1) An identification of each process controller complying with § 60.5390b(a) by using a self-contained natural gas-driven process controller;

(2) Dates of each inspection required under § 60.5416b(b); and

(3) Each defect or leak identified during each natural gas-driven-self-contained process controller system inspection, and date of repair or date of anticipated repair if repair is delayed.

(iii) For each process controller affected facility complying with the § 60.5390b(b)(1) process controller bleed rate requirements, you must maintain records of the information specified in paragraphs (c)(6)(iii)(A) and (B) of this section.

(A) The identification of process controllers designed and operated to achieve a bleed rate less than or equal to 6 scfh and records of the manufacturer's specifications indicating that the process controller is designed with a natural gas bleed rate of less than or equal to 6 scfh.

(B) Where necessary to meet a functional need, the identification of the process controller and demonstration of why it is necessary to use a process controller with a natural gas bleed rate greater than 6 scfh.

(iv) For each intermittent vent process controller in the affected facility complying with the requirements in paragraphs § 60.5390b(b)(2), you must keep records of the information specified in paragraphs (c)(6)(iv)(A) through (C) of this section.

(A) The identification of each intermittent vent process controller.

(B) Dates and results of the intermittent vent process controller monitoring required by § 60.5390b(b)(2)(ii).

(C) For each instance in which monitoring identifies emissions to the atmosphere from an intermittent vent controller during idle periods, the date of repair or replacement, or the date of anticipated repair or replacement if the repair or replacement is delayed and the date and results of the re-survey after repair or replacement.

(v) For each process controller affected facility complying with § 60.5390b(b)(3), you must maintain the records specified in paragraphs (c)(6)(v)(A) and (B) of this section.

(A) An identification of each process controller for which emissions are routed to a control device.

(B) Records specified in paragraphs (c)(8) and (c)(10) through (13) of this section. If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraph (c)(8) of this section, you must provide the information specified in § 60.5424b.

(vi) Records of each change in compliance method, including identification of each natural gas-driven process controller which changes its method of compliance, the new method of compliance, and the date of the change in compliance method.

(vii) Records of each deviation, the date and time the deviation began, the duration of the deviation, and a description of the deviation.

(7) For each storage vessel affected facility, you must maintain the records identified in paragraphs (c)(7)(i) through (vii) of this section.

(i) You must maintain records of the identification and location 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 of each storage vessel affected facility.

(ii) Records of each methane and VOC emissions determination for each storage vessel affected facility made under § 60.5365b(e) including identification of the model or calculation methodology used to calculate the methane and VOC emission rate.

(iii) For each instance where the storage vessel was not operated in compliance with the requirements specified in § 60.5395b a description of the deviation, the date and time each deviation began, and the duration of the deviation.

(iv) If complying with the emissions reduction standard in § 60.5395b(a)(2), you must maintain the records in paragraphs (c)(7)(iv)(A) through (E) of this section.

(A) If you comply with the emission reduction standard with a control device, the information for each control device in paragraphs (c)(11) and (13) of this section.

(B) Records of the closed vent system inspection as specified paragraph (c)(8) of this section. If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraph (c)(8) of this section, you must provide the information specified in § 60.5424b.

(C) Records of the cover inspections as specified in paragraph (c)(9) of this section. If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraphs (c)(9) of this section, you must provide the information specified in § 60.5424b.

(D) If applicable, the records of bypass monitoring as specified in paragraph (c)(10) of this section.

(E) Records of the closed vent system assessment as specified in paragraph (c)(12) of this section.

(v) 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 crude oil and natural gas source category. If a storage vessel is removed from a site and, within 30 days, is either returned to the site 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.

(vi) Records of the date that each storage vessel affected facility or portion of a storage vessel affected facility is removed from service and returned to service, as applicable.

(vii) Records of the date that liquids from the well following fracturing or refracturing are routed to the storage vessel affected facility; or the date that you comply with paragraph § 60.5395b(a)(2), following a

monthly emissions determination which indicates that VOC emissions from your storage vessel affected facility increase to 4 tpy or greater or methane emissions increase to 14 tpy or greater and the increase is not associated with fracturing or refracturing of a well feeding the storage vessel affected facility, and records of the methane and VOC emissions rate and the model or calculation methodology used to calculate the methane and VOC emission rate.

(8) Records of each closed vent system inspection required under § 60.5416b(a)(1) and (2) and (b) for your well, centrifugal compressor, reciprocating compressor, process controller, pump, storage vessel, and process unit equipment affected facility as required in paragraphs (c)(8)(i) through (iv) of this section.

(i) A record of each closed vent system inspection or no identifiable emissions monitoring survey. You must include an identification number for each closed vent system (or other unique identification description selected by you), the date of the inspection, and the method used to conduct the inspection (*i.e.*, visual, AVO, OGI, Method 21 of appendix A-7 to this part).

(ii) For each defect or emissions detected during inspections required by § 60.5416b(a)(1) and (2) or (b), you must record the location of the defect or emissions; a description of the defect; the maximum concentration reading obtained if using Method 21 of appendix A-7 to this part; the indication of emissions detected by AVO if using AVO; the date of detection; the date of each attempt to repair the emissions or defect; the corrective action taken during each attempt to repair the defect; and the date the repair to correct the defect or emissions is completed.

(iii) If repair of the defect is delayed as described in § 60.5416b(b)(6), you must record the reason for the delay and the date you expect to complete the repair.

(iv) Parts of the closed vent system designated as unsafe to inspect as described in § 60.5416b(b)(7) or difficult to inspect as described in § 60.5416b(b)(8), the reason for the designation, and written plan for inspection of that part of the closed vent system.

(9) A record of each cover inspection required under § 60.5416b(a)(3) for your centrifugal compressor, reciprocating compressor, or storage vessel as required in paragraphs (c)(9)(i) through (iv) of this section.

(i) A record of each cover inspection. You must include an identification number for each cover (or other unique identification description selected by you), the date of the inspection, and the method used to conduct the inspection (*i.e.*, AVO, OGI, Method 21 of appendix A-7 to this part).

(ii) For each defect detected during the inspection you must record the location of the defect; a description of the defect, the date of detection, the maximum concentration reading obtained if using Method 21 of appendix A-7 to this part; the indication of emissions detected by AVO if using AVO; the date of each attempt to repair the defect; the corrective action taken during each attempt to repair the defect; and the date the repair to correct the defect is completed.

(iii) If repair of the defect is delayed as described in § 60.5416b(b)(6), you must record the reason for the delay and the date you expect to complete the repair.

(iv) Parts of the cover designated as unsafe to inspect as described in § 60.5416b(b)(7) or difficult to inspect as described in § 60.5416b(b)(8), the reason for the designation, and written plan for inspection of that part of the cover.

(10) For each bypass subject to the bypass requirements of § 60.5416b(a)(4), you must maintain a record of the following, as applicable: readings from the flow indicator; each inspection of the seal or closure mechanism; the date and time of each instance the key is checked out; date and time of each instance the alarm is sounded.

(11) Records for each control device used to comply with the emission reduction standard in § 60.5377b(d) or (f) for associated gas wells, § 60.5380b(a)(1) or (9) for centrifugal compressor affected facilities, § 60.5385b(d)(2) for reciprocating compressor affected facilities, § 60.5390b(b)(3) for your process controller affected facility in Alaska, § 60.5393b(b)(3) for your pump affected facility, § 60.5395b(a)(2) for your storage vessel affected facility, § 60.5376b(g) for well affected facility gas well liquids unloading, or § 60.5400b(f) or 60.5401b(e) for your process equipment affected facility, as required in paragraphs (c)(11)(i) through (viii) of this section. If you use an enclosed combustion device or flare using an alternative test method approved under § 60.5412b(d), keep records of the information in paragraphs (c)(11)(ix) of this section, in lieu of the records required by paragraphs (c)(11)(i) through (iv) and (vi) through (viii) of this section.

(i) For a control device tested under § 60.5413b(d) which meets the criteria in § 60.5413b(d)(11) and (e), keep records of the information in paragraphs (c)(11)(i)(A) through (E) of this section, in addition to the records in paragraphs (c)(11)(ii) through (ix) of this section, as applicable.

(A) Serial number of purchased device and copy of purchase order.

(B) Location of the affected facility associated with the control device 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.

(C) Minimum and maximum inlet gas flow rate specified by the manufacturer.

(D) Records of the maintenance and repair log as specified in § 60.5413b(e)(4), for all inspection, repair, and maintenance activities for each control device failing the visible emissions test.

(E) Records of the manufacturer's written operating instructions, procedures, and maintenance schedule to ensure good air pollution control practices for minimizing emissions.

(ii) For all control devices, keep records of the information in paragraphs (c)(11)(ii)(A) through (G) of this section, as applicable.

(A) Make, model, and date of installation of the control device, and identification of the affected facility controlled by the device.

(B) Records of deviations in accordance with § 60.5417b(g)(1) through (7), including a description of the deviation, the date and time the deviation began, the duration of the deviation, and the cause of the deviation.

(C) The monitoring plan required by § 60.5417b(c)(2).

(D) Make and model number of each continuous parameter monitoring system.

(E) Records of minimum and maximum operating parameter values, continuous parameter monitoring system data (including records that the pilot or combustion flame is present at all times), calculated averages of continuous parameter monitoring system data, and results of all compliance calculations.

(F) Records of continuous parameter monitoring system equipment performance checks, system accuracy audits, performance evaluations, or other audit procedures and results of all inspections specified in the monitoring plan in accordance with § 60.5417b(c)(2). Records of calibration gas cylinders, if applicable.

(G) Periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions and required monitoring system quality assurance or quality control activities. Records of repairs on the monitoring system.

(iii) For each carbon adsorption system, records of the schedule for carbon replacement as determined by the design analysis requirements of § 60.5413b(c)(2) and (3) and records of each carbon replacement as specified in § 60.5412b(c)(1) and § 60.5415b(f)(1)(viii).

(iv) For enclosed combustion devices and flares, records of visible emissions observations as specified in paragraph (c)(11)(iv)(A) or (B) of this section.

(A) Records of observations with Method 22 of appendix A-7 to this part, including observations required following return to operation from a maintenance or repair activity, 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 Method 22 of appendix A-7 to this part.

(B) If you monitor visible emissions with a video surveillance camera, location of the camera and distance to emission source, records of the video surveillance output, and documentation that an operator looked at the feed daily, including the date and start time of observation, the length of observation, and length of time visible emissions were present.

(v) For enclosed combustion devices and flares, video of the OGI inspection conducted in accordance with § 60.5415b(f)(1)(x). Records documenting each enclosed combustion device and flare was visibly observed during each inspection conducted under § 60.5397b using AVO in accordance with § 60.5415b(f)(1)(x).

(vi) For enclosed combustion devices and flares, records of each demonstration of the NHV of the inlet gas to the enclosed combustion device or flare conducted in accordance with § 60.5417b(d)(8)(iii). For each re-evaluation of the NHV of the inlet gas, records of process changes and explanation of the conditions that led to the need to re-evaluation the NHV of the inlet gas. For each demonstration, record information on whether the enclosed combustion device or flare has the potential to receive inert gases, and if so, the highest percentage of inert gases that can be sent to the enclosed combustion device or flare and the highest percent of inert gases sent to the enclosed combustion device or flare during the NHV demonstration. Records of periodic sampling conducted under § 60.5417b(d)(8)(iii)(G).

(vii) For enclosed combustion devices and flares, if you use a backpressure regulator valve, the make and model of the valve, date of installation, and record of inlet flow rating. Maintain records of the engineering evaluation and manufacturer specifications that identify the pressure set point corresponding to the minimum inlet gas flow rate, the annual confirmation that the backpressure regulator valve set point is correct and consistent with the engineering evaluation and manufacturer specifications, and the annual confirmation that the backpressure regulator valve fully closes when not in open position.

(viii) For enclosed combustion devices and flares, records of each demonstration required under § 60.5417b(d)(8)(iv).

(ix) If you use an enclosed combustion device or flare using an alternative test method approved under § 60.5412b(d), keep records of the information in paragraphs (c)(11)(ix)(A) through (H) of this section, in lieu of the records required by paragraphs (c)(11)(i) through (iv) and (c)(11)(vi) through (viii) of this section.

(A) An identification of the alternative test method used.

(B) Data recorded at the intervals required by the alternative test method.

(C) Monitoring plan required by § 60.5417(i)(2).

(D) Quality assurance and quality control activities conducted in accordance with the alternative test method.

(E) If required by § 60.5412b(d)(4) to conduct visible emissions observations, records required by paragraph (c)(11)(iv) of this section.

(F) If required by § 60.5412b(d)(5) to conduct pilot or combustion flame monitoring, record indicating the presence of a pilot or combustion flame and periods when the pilot or combustion flame is absent.

(G) For each instance where there is a deviation of the control device in accordance with § 60.5417b(i)(6)(i) through (v), the date and time the deviation began, the duration of the deviation in hours, and cause of the deviation.

(H) Any additional information required to be recorded as specified by the Administrator as part of the alternative test method approval under § 60.5412b(d).

(12) For each closed vent system routing to a control device or process, the records of the assessment conducted according to § 60.5411b(c):

(i) A copy of the assessment conducted according to § 60.5411b(c)(1); and

(ii) A copy of the certification according to § 60.5411b(c)(1)(i) and (ii).

(13) A copy of each performance test submitted under paragraphs (b)(12) or (13) of this section.

(14) For the fugitive emissions components affected facility, maintain the records identified in paragraphs (c)(14)(i) through (viii) of this section.

(i) The date of the startup of production or the date of the first day of production after modification for the fugitive emissions components affected facility at a well site and the date of startup or the date of modification for the fugitive emissions components affected facility at a compressor station.

(ii) For the fugitive emissions components affected facility at a well site, you must maintain records specifying what type of well site it is (*i.e.*, single wellhead only well site, small wellsite, multi-wellhead only well site, or a well site with major production and processing equipment.)

(iii) For the fugitive emissions components affected facility at a well site where you complete the removal of all major production and processing equipment such that the well site contains only one or more wellheads, record the date the well site completes the removal of all major production and processing equipment from the well site, and, if the well site is still producing, record the well ID or separate tank battery ID receiving the production from the well site. If major production and processing equipment is subsequently added back to the well site, record the date that the first piece of major production and processing equipment is added back to the well site.

(iv) The fugitive emissions monitoring plan as required in § 60.5397b(b), (c), and (d).

(v) The records of each monitoring survey as specified in paragraphs (c)(14)(v)(A) through (I) of this section.

(A) Date of the survey.

(B) Beginning and end time of the survey.

(C) Name of operator(s), training, and experience of the operator(s) performing the survey.

(D) Monitoring instrument or method used.

(E) Fugitive emissions component identification when Method 21 of appendix A-7 to this part is used to perform the monitoring survey.

(F) Ambient temperature, sky conditions, and maximum wind speed at the time of the survey. For compressor stations, operating mode of each compressor (*i.e.*, operating, standby pressurized, and not operating-depressurized modes) at the station at the time of the survey.

(G) Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.

(H) Records of calibrations for the instrument used during the monitoring survey.

(I) Documentation of each fugitive emission detected during the monitoring survey, including the information specified in paragraphs (c)(14)(v)(I)(1) through (9) of this section.

(1) Location of each fugitive emission identified.

(2) Type of fugitive emissions component, including designation as difficult-to-monitor or unsafe-to-monitor, if applicable.

(3) If Method 21 of appendix A-7 to this part is used for detection, record the component ID and instrument reading.

(4) For each repair that cannot be made during the monitoring survey when the fugitive emissions are initially found, a digital photograph or video must be taken of that component or the component must be tagged for identification purposes. The digital photograph must include the date that the photograph was taken and must clearly identify the component by location within the site (*e.g.*, the latitude and longitude of the component or by other descriptive landmarks visible in the picture). The digital photograph or identification (*e.g.*, tag) may be removed after the repair is completed, including verification of repair with the resurvey.

(5) The date of first attempt at repair of the fugitive emissions component(s).

(6) The date of successful repair of the fugitive emissions component, including the resurvey to verify repair and instrument used for the resurvey.

(7) Identification of each fugitive emission component placed on delay of repair and explanation for each delay of repair.

(8) For each fugitive emission component placed on delay of repair for reason of replacement component unavailability, the operator must document: the date the component was added to the delay of repair list, the date the replacement fugitive component or part thereof was ordered, the anticipated component delivery date (including any estimated shipment or delivery date provided by the vendor), and the actual arrival date of the component.

(9) Date of planned shutdowns that occur while there are any components that have been placed on delay of repair.

(vi) For the fugitive emissions components affected facility complying with an alternative means of emissions limitation under § 60.5399b, you must maintain the records specified by the specific alternative fugitive emissions standard for a period of at least 5 years.

(vii) For well closure activities, you must maintain the information specified in paragraphs (c)(14)(vii)(A) through (G) of this section.

(A) The well closure plan developed in accordance with § 60.5397b(l) and the date the plan was submitted.

(B) The notification of the intent to close the well site and the date the notification was submitted.

(C) The date of the cessation of production from all wells at the well site.

(D) The date you began well closure activities at the well site.

(E) Each status report for the well closure activities reported in paragraph (b)(9)(iv)(A) of this section.

(F) Each OGI survey reported in paragraph (b)(9)(iv)(B) of this section including the date, the monitoring instrument used, and the results of the survey or resurvey.

(G) The final OGI survey video demonstrating the closure of all wells at the site. The video must include the date that the video was taken and must identify the well site location by latitude and longitude.

(viii) If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraphs (c)(14)(iv) and (v) of this section, you must maintain the records specified in § 60.5424b.

(15) For each pump affected facility, you must maintain the records identified in paragraphs (c)(15)(i) through (ix) of this section.

(i) Identification of each pump that is driven by natural gas and that is in operation 90 days or more per calendar year.

(ii) If you are complying with § 60.5393b(a) or (b)(1) by routing pump vapors to a process through a closed vent system, identification of all the pumps in the pump affected facility for which you collect and route vapors to a process through a closed vent system and the records specified in paragraphs (c)(8), (10), and (12) of this section. If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraph (c)(8) of this section, you must provide the information specified in § 60.5424b.

(iii) If you are complying with § 60.5393b(b)(1) by routing pump vapors to control device achieving a 95.0 percent reduction in methane and VOC emissions, you must keep the records specified in paragraphs (c)(8) and (10) through (c)(13) of this section. If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraph (c)(8) of this section, you must provide the information specified in § 60.5424b.

(iv) If you are complying with § 60.5393b(b)(5) by routing pump vapors to control device achieving less than a 95.0 percent reduction in methane and VOC emissions, you must maintain records of the certification that there is a control device on site but it does not achieve a 95.0 percent emissions reduction and a record of the design evaluation or manufacturer's specifications which indicate the percentage reduction the control device is designed to achieve.

(v) If you have less than three natural gas-driven diaphragm pumps in the pump affected facility, and you do not have a vapor recovery unit or control device installed on site by the compliance date, you must retain a record of your certification required under § 60.5393b(b)(6), certifying that there is no vapor recovery unit or control device on site. If you subsequently install a control device or vapor

recovery unit, you must maintain the records required under paragraph (c)(15)(ii) and paragraph (c)(15)(iii) or (iv) of this section, as applicable.

(vi) If you determine, through an engineering assessment, that it is technically infeasible to route the pump affected facility emissions to a process or control device, you must retain records of your demonstration and certification that it is technically infeasible as required under § 60.5393b(b)(5).

(vii) If the pump is routed to a control device that is subsequently removed from the location or is no longer available such that there is no option to route to a control device, you are required to retain records of this change and the records required under paragraph (c)(15)(vi) of this section.

(viii) Records of each change in compliance method, including identification of each natural gas-driven pump which changes its method of compliance, the new method of compliance, and the date of the change in compliance method.

(ix) Records of each deviation, the date and time the deviation began, the duration of the deviation, and a description of the deviation.

(d) *Electronic reporting.* If you are required to submit notifications or reports following the procedure specified in this paragraph (d), you must submit notifications or reports to the EPA via CEDRI, which can be accessed through the EPA's Central Data Exchange (CDX) (<https://cdx.epa.gov/>). The EPA will make all the information submitted through CEDRI available to the public without further notice to you. Do not use CEDRI to submit information you claim as CBI. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim for some of the information in the report or notification, you must submit a complete file in the format specified in this subpart, including information claimed to be CBI, to the EPA following the procedures in paragraphs (d)(1) and (2) of this section. Clearly mark the part or all of the information that you claim to be CBI. Information not marked as CBI may be authorized for public release without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. All CBI claims must be asserted at the time of submission. Anything submitted using CEDRI cannot later be claimed CBI. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available. You must submit the same file submitted to the CBI office with the CBI omitted to the EPA via the EPA's CDX as described earlier in this paragraph (d).

(e) *Claims of EPA system outage.* If you are required to electronically submit a notification or report through CEDRI in the EPA's CDX, you may assert a claim of EPA system outage for failure to timely comply with that requirement. To assert a claim of EPA system outage, you must meet the requirements outlined in paragraphs (e)(1) through (7) of this section.

- (1) You must have been or will be precluded from accessing CEDRI and submitting a required report within the time prescribed due to an outage of either the EPA's CEDRI or CDX systems.
- (2) The outage must have occurred within the period of time beginning five business days prior to the date that the submission is due.
- (3) The outage may be planned or unplanned.
- (4) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.
- (5) You must provide to the Administrator a written description identifying:
 - (i) The date(s) and time(s) when CDX or CEDRI was accessed and the system was unavailable;

- (ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to EPA system outage;
- (iii) A description of measures taken or to be taken to minimize the delay in reporting; and
- (iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(6) The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(7) In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved.

(f) *Claims of force majeure.* If you are required to electronically submit a report or notification through CEDRI in the EPA's CDX, you may assert a claim of *force majeure* for failure to timely comply with that requirement. To assert a claim of *force majeure*, you must meet the requirements outlined in paragraphs (f)(1) through (5) of this section.

(1) You may submit a claim if a *force majeure* event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning five business days prior to the date the submission is due. For the purposes of this section, a *force majeure* event is defined as an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents you from complying with the requirement to submit a report electronically within the time period prescribed. Examples of such events are acts of nature (*e.g.*, hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility (*e.g.*, large scale power outage).

(2) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(3) You must provide to the Administrator:

- (i) A written description of the *force majeure* event;
- (ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to the *force majeure* event;
- (iii) A description of measures taken or to be taken to minimize the delay in reporting; and
- (iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(4) The decision to accept the claim of *force majeure* and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(5) In any circumstance, the reporting must occur as soon as possible after the *force majeure* event occurs.

§ 60.5421b What are my additional recordkeeping requirements for process unit equipment affected facilities?

You must maintain a record of each equipment leak monitoring inspection and each leak identified under § 60.5400b and § 60.5401b as specified in paragraphs (b)(1) through (17) of this section. The record must be maintained either onsite or at the nearest local field office for at least 5 years. Any records required to be maintained that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to a delegated air agency or the EPA as part of an on-site compliance evaluation.

- (a) You may comply with the recordkeeping requirements for multiple process unit equipment affected facilities in one recordkeeping system if the system identifies each record by each facility.
- (b) You must maintain the monitoring inspection records specified in paragraphs (b)(1) through (17) of this section.
- (1) Equipment Identification. Note that connectors need not be individually identified if all connectors in a designated area or length of pipe subject to the provisions of this subpart are identified as a group, and the number of connectors subject is indicated.
 - (2) Date and start and end times of the monitoring inspection.
 - (3) Inspector name.
 - (4) Leak determination method used for the monitoring inspection (*i.e.*, OGI, Method 21, or AVO).
 - (5) Monitoring instrument identification (OGI and Method 21 only).
 - (6) Type of equipment monitored.
 - (7) Process unit identification.
 - (8) The records specified in Section 12 of appendix K of this part, for each monitoring inspection conducted with OGI.
 - (9) The records in paragraph (b)(9)(i) through (vii), for each monitoring inspection conducted with Method 21 of appendix A-7 to this part.
 - (i) Instrument reading.
 - (ii) Date and time of instrument calibration and initials of operator performing the calibration.
 - (iii) Calibration gas cylinder identification, certification date, and certified concentration.
 - (iv) Instrument scale used.
 - (v) A description of any corrective action taken if the meter readout could not be adjusted to correspond to the calibration gas value in accordance with section 10.1 of Method 21 of appendix A-7 to this part.
 - (vi) Results of the daily calibration drift assessment.
 - (vii) If you make your own calibration gas, a description of the procedure used.
 - (10) For visual inspections of pumps in light liquid service, keep the records specified in paragraphs (b)(10)(i) through (iii), for each monitored equipment:
 - (i) Date of inspection.
 - (ii) Inspector name.
 - (iii) Result of inspection (*i.e.*, visual indications of liquids dripping from the pump seal or no visual indications of liquids dripping from the pump seal).
 - (11) For each leak detected, the records specified in paragraphs (b)(11)(i) through (v) of this section:
 - (i) The instrument and operator identification numbers and the process unit and equipment identification numbers. For leaks identified via AVO methods, enter the specific sensory method for instrument identification number.
 - (ii) The date the leak was detected.
 - (iii) For each attempt to repair the leak, record:

- (A) The date.
- (B) The repair method applied.
- (C) Indication of whether a leak was still detected following each attempt to repair the leak.
- (iv) The date of successful repair of the leak and the method of monitoring used to confirm the repair, as specified in paragraph (b)(11)(iv)(A) through (C) of this section.
 - (A) If Method 21 of appendix A-7 to this part is used to confirm the repair, maintain a record of the maximum instrument reading measured by Method 21 of appendix A-7 to this part.
 - (B) If OGI conducted in accordance with appendix K of this part is used to confirm the repair, maintain a record of video footage of the repair confirmation.
 - (C) If the leak is repaired by eliminating AVO indications of a leak, maintain a record of the specific sensory method used to confirm that the evidence of the leak is eliminated.
- (v) For each repair delayed beyond 15 calendar days after detection of the leak, record:
 - (A) "Repair delayed" and the reason for the delay.
 - (B) The signature of the certifying official who made the decision that repair could not be completed without a process shutdown.
 - (C) The expected date of successful repair of the leak.
 - (D) Dates of process unit shutdowns that occur while the equipment is unrepaired.
- (12) A list of identification numbers for equipment that are designated for no detectable emissions complying with the provisions of § 60.5401b.
- (13) A list of identification numbers for valves, pumps, and connectors that are designated as unsafe-to-monitor, an explanation for each valve, pump, or connector stating why the valve, pump, or connector is unsafe-to-monitor, and the plan for monitoring each valve, pump, or connector.
- (14) A list of identification numbers for valves that are designated as difficult-to-monitor, an explanation for each valve stating why the valve is difficult-to-monitor, and the schedule for monitoring each valve.
- (15) A list of identification numbers for equipment that is in vacuum service.
- (16) A list of identification numbers for equipment you designate as having the potential to emit methane or VOC less than 300 hr/yr.
- (17) A list of identification numbers for valves where it was infeasible to replace leaking valves with low-e valves or repack existing valves with low-e packing technology, including the reasoning for why it was infeasible.

§ 60.5422b What are my additional reporting requirements for process unit equipment affected facilities?

- (a) You must submit semiannual reports using the appropriate electronic report template on the CEDRI website for this subpart and following the procedure specified in § 60.5420b(d). If the reporting form specific to this subpart is not available on the CEDRI website at the time that the report is due, submit the report to the Administrator at the appropriate address listed in § 60.4. Once the form has been available on the CEDRI website for at least 90 calendar days, you must begin submitting all subsequent reports via CEDRI. The date reporting forms become available will be listed on the CEDRI website. Unless the Administrator or delegated state agency or other authority has approved a different schedule for submission of reports, the report must be submitted within 45 days after the end of the semiannual reporting period, regardless of the method in which the report is submitted.
- (b) The initial semiannual report must include the following information:

- (1) The general information specified in paragraph (c)(1) of this section.
- (2) For each process unit:
 - (i) Process unit identification.
 - (ii) Number of valves subject to the monitoring requirements of §§ 60.5400b(b) and 60.5401b(f).
 - (iii) Number of pumps subject to the monitoring requirements of §§ 60.5400b(b) and 60.5401b(b).
 - (iv) Number of connectors subject to the monitoring requirements of §§ 60.5400b(b) and 60.5401b(h).
 - (v) Number of pressure relief devices subject to the monitoring requirements of §§ 60.5400b(b) and 60.5401b(c).
 - (vi) The information in paragraphs (c)(3) and (4) of this section.
- (c) All subsequent semiannual reports must include the following information:
 - (1) The general information specified in paragraphs (c)(1)(i) through (iii) of this section.
 - (i) The company name, facility site name, and address of the affected facility.
 - (ii) Beginning and ending dates of the reporting period.
 - (iii) A certification by a certifying official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. If your report is submitted via CEDRI, the certifier's electronic signature during the submission process replaces the requirement in this paragraph (c)(1)(iii).
 - (2) Process unit identification for each process unit.
 - (3) For each month during the semiannual reporting period for each process unit report:
 - (i) Number of valves for which leaks were detected as described in § 60.5400b(b) or § 60.5401b(f).
 - (ii) Number of valves for which leaks were not repaired as required in § 60.5400b(h) or § 60.5401b(i), the number of instances where it was technically infeasible to replace leaking valves with low-e valves or repack existing valves with low-e packing technology, including the reasoning for why it was technically infeasible.
 - (iii) Number of pumps for which leaks were detected as described § 60.5400b(b) or § 60.5401b(b).
 - (iv) Number of pumps for which leaks were not repaired as required in § 60.5400b(h) or § 60.5401b(i).
 - (v) Number of connectors for which leaks were detected as described in § 60.5400b(b) or § 60.5401b(h).
 - (vi) Number of connectors for which leaks were not repaired as required in § 60.5400b(h) or § 60.5401b(i).
 - (vii) Number of pressure relief devices for which leaks were detected as described in § 60.5400b(b) or § 60.5401b(c).
 - (viii) Number of pressure relief devices for which leaks were not repaired as required in § 60.5400b(h) or § 60.5401b(i).
 - (ix) Number of open-ended valves or lines for which leaks were detected as described in § 60.5400b(e) or § 60.5401b(d).

(x) Number of open-ended valves or lines for which leaks were not repaired as required in § 60.5400b(h) or § 60.5401b(i).

(xi) Number of pumps, valves, or connectors in heavy liquid service or pressure relief device in light liquid or heavy liquid service for which leaks were detected as described in § 60.5400b(g) or § 60.5401b(g).

(xii) Number of pumps, valves, or connectors in heavy liquid service or pressure relief device in light liquid or heavy liquid service for which leaks were not repaired as required in § 60.5400b(h) or § 60.5401b(i).

(xiii) The facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible.

(4) Dates of process unit shutdowns which occurred within the semiannual reporting period.

(5) Revisions to items reported according to paragraph (b) of this section if changes have occurred since the initial report or subsequent revisions to the initial report.

§ 60.5423b What are my additional recordkeeping and reporting requirements for sweetening unit affected facilities?

(a) You must retain records of the calculations and measurements required in §§ 60.5405b(a) and (b) and 60.5407b(a) through (g) for at least 2 years following the date of the measurements. This requirement is included under § 60.7(f) of the General Provisions.

(b) In your initial annual report submitted in accordance with the procedures and schedule in § 60.5420b(b), include the information in paragraphs (b)(1) and (2) of this section.

(1) For each run of the initial performance test required by § 60.8(b):

(i) The average sulfur feed rate in Mg/D, determined according to § 60.5406b(b).

(ii) The average volumetric flow rate of acid gas from the sweetening unit, in dscm/day.

(iii) The H₂S concentration in the acid gas feed from the sweetening unit, percent by volume.

(iv) The emission rate of sulfur in kg/hr.

(v) The sulfur production rate in kg/hr.

(vi) The emission reduction efficiency achieved by the sulfur recovery technology, determined according to § 60.5406b(c).

(vii) The required initial SO₂ emission reduction efficiency, as determined from table 3 to this subpart based on the sulfur feed rate and the sulfur content of the acid gas of the affected facility.

(2) The required minimum SO₂ emission reduction efficiency you must achieve on a continuous basis, as determined from table 4 to this subpart based on the sulfur feed rate and the sulfur content of the acid gas of the affected facility.

(c) You must submit the performance test report in accordance with the requirements of § 60.5420b(b)(12).

(d) You must submit a report of excess emissions to the Administrator in your annual report if you had excess emissions during the reporting period. The procedures and schedule for submitting annual reports are located in § 60.5420b(b). For the purpose of these reports, excess emissions are defined as specified in paragraphs (d)(1) and (2) of this section. The report must contain the information specified in paragraph (d)(3) of this section.

(1) Any 24-hour period (at consistent intervals) during which the average sulfur emission reduction efficiency (R) is less than the minimum required efficiency (Z).

(2) For any affected facility electing to comply with the provisions of § 60.5407b(b)(2), any 24-hour period during which the average temperature of the gases leaving the combustion zone of an incinerator is less than the appropriate operating temperature as determined during the most recent performance test in accordance with the provisions of § 60.5407b(b)(3). Each 24-hour period must consist of at least 96 temperature measurements equally spaced over the 24 hours.

(3) For each period of excess emissions during the reporting period, include the following information in your report:

- (i) The date and time of commencement and completion of each period of excess emissions;
- (ii) The required minimum efficiency (Z) and the actual average sulfur emissions reduction (R) for periods defined in paragraph (d)(1) of this section; and
- (iii) The appropriate operating temperature and the actual average temperature of the gases leaving the combustion zone for periods defined in paragraph (d)(2) of this section.

(e) To certify that a facility is exempt from the control requirements of these standards, for each facility with a design capacity less than 2 LT/D of H₂S in the acid gas (expressed as sulfur) you must keep, for the life of the facility, an analysis demonstrating that the facility's design capacity is less than 2 LT/D of H₂S expressed as sulfur.

(f) If you elect to comply with § 60.5407b(e) you must keep, for the life of the facility, a record demonstrating that the facility's design capacity is less than 150 LT/D of H₂S expressed as sulfur.

(g) The requirements of paragraph (d) of this section remain in force until and unless the EPA, in delegating enforcement authority to a state under section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such state. In that event, affected sources within the state will be relieved of obligation to comply with paragraph (d) of this section, provided they comply with the requirements established by the state. Electronic reporting to the EPA cannot be waived, and as such, the provisions of this paragraph do not relieve owners or operators of affected facilities of the requirement to submit the electronic reports required in this section to the EPA.

§ 60.5424b What are my additional recordkeeping and reporting requirements if I comply with the alternative GHG and VOC standards for fugitive emissions components affected facilities and covers and closed vent systems?

This section provides notification, reporting, and recordkeeping requirements for owners and operators who choose to comply with an alternative GHG and VOC standard as specified in § 60.5398b for fugitive emissions components affected facilities and the alternative continuous inspection and monitoring requirements for covers and closed vent systems. You must submit an annual report in accordance with the schedule in § 60.5420b(b) which includes the information in paragraphs (a)(1), (b), and (d) of this section, as applicable. You must submit the notification in paragraph (a)(2) of this section and maintain the records in paragraphs (c) and (e) of this section, as applicable.

(a) *Notifications.* If you choose to comply with an alternative GHG and VOC standard as specified in § 60.5398b for fugitive emissions components affected facilities and the alternative continuous inspection and monitoring requirements for covers and closed vent systems, you must submit the notification in paragraph (a)(1) of this section. If you are required by § 60.5398b(c)(8) to develop a mass emission rate reduction plan, you must submit the notification in paragraph (a)(2) of this section.

(1) A notification to the Administrator of adoption of the alternative standards in the annual report required by § 60.5420b(b)(4) through (11).

(2) A notification, which includes the submittal of the mass emission rate reduction plan required by § 60.5398b(c)(8). You must submit the mass emission rate reduction plan to the Administrator within 60 days of the initial exceedance of the action level.

(b) *Information submittal.* If you comply with the periodic screening requirements of § 60.5398b(b), you must submit the information in paragraphs (b)(1) through (6) of this section in the annual report required by § 60.5420b(b)(4) through (11).

(1) Date of each periodic screening during the reporting period and date that results of the periodic screening were received.

(2) Alternative test method and technology used for each screening and the spatial resolution of the technology (*i.e.*, facility-level, area-level, or component-level).

(3) Any deviations from the monitoring plan developed under § 60.5398b(b)(2) or a statement that there were no deviations from the monitoring plan.

(4) Results from each periodic screening during the reporting period. If the results of the periodic screening indicate a confirmed detection of emissions from an affected facility, you must submit the information in paragraphs (b)(4)(i) through (iv) of this section.

(i) The date that the monitoring survey of your entire or the required portion of your fugitive emissions components affected facility was conducted.

(ii) The date that you completed the instrument inspections of all required covers and closed vent systems(s).

(iii) The date that you conducted the visual inspection for emissions of all required covers and closed vent systems.

(iv) For each fugitive emission from a fugitive emissions components affected facility and all emissions or defects of each cover and closed vent system, you must submit the information in paragraphs (b)(4)(iv)(A) through (D) of this section.

(A) Number and type of components for which fugitive emissions were detected.

(B) Each emission or defect identified during the inspection for each cover and closed vent system.

(C) Date of repair for each fugitive emission from a fugitive emissions components affected facility or each emission or defect for each cover and closed vent system.

(D) Number and type of fugitive emission components and identification of each cover or closed vent system placed on delay of repair and an explanation for each delay of repair.

(5) The information in paragraphs (b)(5)(i) through (iv) of this section if you are required to conduct OGI surveys in accordance with § 60.5398b(b)(1)(i) or if you replace a periodic screening event with an OGI survey in accordance with § 60.5398b(b)(1)(iv).

(i) The date of the OGI survey.

(ii) Number and type of components for which fugitive emissions were detected.

(iii) Number and type of fugitive emissions components that were not repaired as required in § 60.5397b(h).

(iv) Number and type of fugitive emission components placed on delay of repair and an explanation for each delay of repair.

(6) Any additional information regarding the performance of the periodic screening technology as specified by the Administrator, as part of the alternative test method approval described in § 60.5398b(d).

(c) *Maintain records.* If you comply with the periodic screening requirements of § 60.5398b(b), you must maintain the records in paragraphs (c)(1) through (11) of this section in addition to the records as specified in § 60.5420b(c)(3) through (9) and (c)(14) and (15).

- (1) The monitoring plan as required in § 60.5398b(b)(2).
- (2) Date of each periodic screening and date that results of the periodic screening were received.
- (3) Name of screening operator.
- (4) Alternative test method and technology used for screening, as well as the aggregate detection threshold for the technology and the spatial resolution of the technology (*i.e.*, facility-level, area-level, or component-level).
- (5) Records of calibrations for technology used during the screening if calibration is required by the alternative test method approved in accordance with § 60.5398b(d).
- (6) Results from periodic screening. If the results of the periodic screening indicate a confirmed detection of emissions from an affected facility, you must maintain the records in paragraphs (c)(6)(i) through (v) of this section.

(i) The date of the inspection of the fugitive emissions components and inspection of covers and closed vent system, as specified in § 60.5398b(b)(5).

(ii) Name of operator(s) performing the survey or inspection.

(iii) For surveys and instrument inspections, identification of the monitoring instrument(s) used.

(iv) Records of calibrations for the instrument(s) used during the survey or instrument inspection, as applicable.

(v) For each fugitive emission from a fugitive emissions components affected facility and each leak or defect for each cover and closed vent system inspection, you must maintain the records in paragraphs (c)(6)(v)(A) through (F) of this section.

(A) The location of the fugitive emissions identified using a unique identifier for the source of the emissions and the type of fugitive emissions component.

(B) The location of the emission or defect from a cover or closed vent system using a unique identifier for the source of the emission or defect.

(C) If a defect of a closed vent system, cover, or control device is identified, a description of the defect.

(D) The date of repair for each fugitive emission from a fugitive emissions components affected facility or each emission or defect for each cover and closed vent system.

(E) Number and type of fugitive emission components and identification of each cover or closed vent system placed on delay of repair and an explanation for each delay of repair.

(F) For each fugitive emission component placed on delay of repair for reason of replacement component unavailability, the operator must document: the date the component was added to the delay of repair list, the date the replacement fugitive component or part thereof was ordered, the anticipated component delivery date (including any estimated shipment or delivery date provided by the vendor), and the actual arrival date of the component.

(7) The date the investigative analysis was initiated, and the result of the investigative analysis conducted in accordance with § 60.5398b(b)(5)(vi) and (vii), as applicable.

(8) Dates of implementation and completion of action(s) taken as a result of the investigative analysis and a description of the action(s) taken in accordance with § 60.5398b(b)(5)(vi) and (vii), as applicable.

(9) The information in paragraphs (c)(9)(i) through (vii) of this section if you are required to conduct OGI surveys in accordance with § 60.5398b(b)(1)(i) or if you replace a periodic screening event with an OGI survey in accordance with § 60.5398b(b)(1)(iv).

(i) The date of the OGI survey.

(ii) Location of each fugitive emission identified.

(iii) Type of fugitive emissions component for which fugitive emissions were detected.

(iv) The date of first attempt at repair of the fugitive emissions component(s).

(v) The date of successful repair of the fugitive emissions component(s), including the resurvey to verify the repair.

(vi) Identification of each fugitive emissions component placed on delay of repair and an explanation for each delay of repair.

(vii) For each fugitive emission component placed on delay of repair for reason of replacement component unavailability, the operator must document: the date the component was added to the delay of repair list, the date the replacement fugitive component or part thereof was ordered, the anticipated component delivery date (including any estimated shipment or delivery date provided by the vendor), and the actual arrival date of the component.

(10) Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.

(11) All records required by the alternative approved in accordance with § 60.5398b(d).

(d) *Information submittal.* If you comply with the continuous monitoring system requirements of § 60.5398b(c), you must submit the information in paragraphs (d)(1) through (6) of this section in the annual report required by § 60.5420b(b)(4) through (11).

(1) The start date and end date for each period where the emissions rate determined in accordance with § 60.5398b(c)(6) exceeded one of the action levels determined in accordance with § 60.5398b(c)(4). Include which action level was exceeded (the 7-day or 90-day rolling average), the numerical value of the action level, and the mass emission rate calculated by the continuous monitoring system in the report.

(2) The date the investigative analysis was initiated, and the result of the investigative analysis conducted in accordance with § 60.5398b(c)(7), as applicable.

(3) Dates of implementation and completion of action(s) taken to reduce the mass emission rate and a description of the action(s) taken in accordance with § 60.5398b(c)(7), as applicable.

(4) If there are no instances reported under paragraph (d)(1) of this section, report your numerical action levels and the highest 7-day rolling average and highest 90-day rolling average determined by your continuous monitoring system during the reporting period.

(5) The start date for each instance where the 12-month rolling average operational downtime of the system exceeded 10 percent and the value of the 12-month rolling average operational downtime during the period. If there were no instances during the reporting period where the 12-month rolling average operational downtime of the system exceeded 10 percent, report the highest value of the 12-month rolling average operational downtime during the reporting period.

(6) Any additional information regarding the performance of the continuous monitoring system as specified by the Administrator, as part of the alternative test method approval described in § 60.5398b(d).

(e) *Maintain records.* If you comply with the continuous monitoring system requirements of § 60.5398b(c), you must maintain the records in paragraphs (e)(1) through (15) of this section.

(1) The monitoring plan required by § 60.5398b(c)(2).

(2) Date of commencement of continuous monitoring with your continuous monitoring system.

(3) The detection threshold of the continuous monitoring system.

(4) The results of checks for power and function in accordance with § 60.5398b(c)(1)(ii).

(5) The beginning and end of each period of operational downtime for the system.

(6) Each rolling 12-month average operational downtime for the system, calculated in accordance with § 60.5398b(c)(1)(iv)(D).

(7) The 7-day rolling average and 90-day rolling average action levels for the site determined in accordance with § 60.5398b(c)(4).

(8) The information in paragraphs (e)(8)(i) through (v) of this section each time you establish site-specific baseline emissions in accordance with § 60.5398b(c)(5).

(i) Records of inspections of fugitive emissions components, covers, and closed vent systems required by § 60.5398b(c)(5)(i), including the date of inspection, location of each emission or defect identified, date of successful repair of each fugitive emissions component, cover, or closed vent system.

(ii) Records of inspections of control devices required by § 60.5398b(c)(5)(ii), including the date of the inspection and the results of the inspection.

(iii) The start date and time and end date and time of any maintenance activities that occurred during the 30 operating day period.

(iv) The site-level emission rate for each day during the 30 operating day period.

(v) The calculated site-specific baseline emission rate.

(9) Each methane mass emission rate reading determined by the system.

(10) Each daily, 7-day, and 90-day average mass emission rate which was determined in accordance with § 60.5398b(c)(6). If you exceed the 90-day action level, you must also keep records of the 30-day average mass emission rate following completion of the initial actions to reduce the average mass emission rate, in accordance with § 60.5398b(c)(8)(i).

(11) The results of each comparison of the emissions rate determined in accordance with § 60.5398b(c)(6) to the action level determined in accordance with § 60.5398b(c)(4).

(12) The date the investigative analysis was initiated, and the result of the investigative analysis conducted in accordance with § 60.5398b(c)(7), as applicable.

(13) Dates of implementation and completion of action(s) taken to reduce the mass emission rate below the action level and a description of the action(s) taken in accordance with § 60.5398b(c)(7), as applicable.

(14) Each mass emission rate reduction plan developed in accordance with § 60.5398b(c)(8), as applicable. You must keep records of the actions taken in accordance with the plan and the date such actions are taken.

(15) Any additional information regarding the performance of the continuous monitoring technology as specified by the Administrator, as part of the alternative test method approval described in § 60.5398b(d).

§ 60.5425b What parts of the General Provisions apply to me?

Table 5 to this subpart shows which parts of the General Provisions in §§ 60.1 through 60.19 apply to you.

§ 60.5430b What definitions apply to this subpart?

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

Access to electrical power means commercial line power is available onsite, with sufficient capacity to support the required power loading of onsite equipment, and which provides reliable and consistent power.

Acid gas means a gas stream of hydrogen sulfide (H₂S) and carbon dioxide (CO₂) that has been separated from sour natural gas by a sweetening unit.

Alaskan North Slope means the approximately 69,000 square-mile area extending from the Brooks Range to the Arctic Ocean.

API Gravity means the weight per unit volume of hydrocarbon liquids as measured by a system recommended by the American Petroleum Institute (API) and is expressed in degrees.

Artificial lift equipment means mechanical pumps including, but not limited to, rod pumps and electric submersible pumps used to flowback fluids from a well.

Associated gas means the natural gas from wells operated primarily for oil production that is released from the liquid hydrocarbon during the initial stage of separation after the wellhead. Associated gas production begins at the startup of production after the flow back period ends. Gas from wildcat or delineation wells is not associated gas.

Average aggregate detection threshold means:

(1) For the purposes of § 60.5398b, the average of all site-level detection thresholds from a single deployment (e.g., a singular flight that surveys multiple well sites, centralized production facility, and/or compressor stations) of a technology; and

(2) For the purposes of § 60.5371b, the average of all site-level detection thresholds from a single deployment in the same basin and field.

Bleed rate means the rate in standard cubic feet per hour at which natural gas is continuously vented (bleeds) from a process controller.

Capital expenditure means, as an alternative to the definition in 40 CFR 60.2, an expenditure for a physical or operational change to an existing facility that:

(1) Exceeds P, the product of the facility's replacement cost, R, and an adjusted annual asset guideline repair allowance, A, as reflected by the following equation: $P = R \times A$, where:

(i) The adjusted annual asset guideline repair allowance, A, is the product of the percent of the replacement cost, Y, and the applicable basic annual asset guideline repair allowance, B, divided by 100 as reflected by the following equation: $A = Y \times (B \div 100)$;

(ii) The percent Y is determined from the following equation: $Y = (\text{CPI of date of construction} / \text{most recently available CPI of date of project})$, where the "CPI-U, U.S. city average, all items" must be used for each CPI value; and

(iii) The applicable basic annual asset guideline repair allowance, B, is 4.5.

(2) [Reserved]

Centralized production facility means one or more storage vessels and all equipment at a single surface site used to gather, for the purpose of sale or processing to sell, crude oil, condensate, produced water, or intermediate hydrocarbon liquid from one or more offsite natural gas or oil production wells. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline. Process vessels and process tanks are not considered storage vessels or storage tanks. A centralized production facility is located upstream of the natural gas processing plant or the crude oil pipeline breakout station and is a part of producing operations.

Centrifugal compressor means any machine for raising the pressure of a natural gas by drawing in low pressure natural gas and discharging significantly higher-pressure natural gas by means of mechanical rotating vanes or impellers. Screw, sliding vane, and liquid ring compressors are not centrifugal compressors for the purposes of this subpart.

Centrifugal compressor equipped with sour seal oil separator and capture system means a wet seal centrifugal compressor system which has an intermediate closed process that degasses most of the gas entrained in the sour seal oil and sends that gas to either another process or combustion device (*i.e.*, degassed emissions are recovered). The de-gas emissions are routed back to a process or combustion device directly from the intermediate closed degassing process; after the intermediate closed process the oil is ultimately recycled for recirculation in the seals to the lube oil tank where any small amount of residual gas is released through a vent.

Certifying official means one of the following:

(1) For a corporation: A president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities with an affected facility subject to this subpart and either:

(i) The facilities employ more than 250 persons or have gross annual sales or expenditures exceeding \$25 million (in second quarter 1980 dollars); or

(ii) The Administrator is notified of such delegation of authority prior to the exercise of that authority. The Administrator reserves the right to evaluate such delegation;

(2) For a partnership (including but not limited to general partnerships, limited partnerships, and limited liability partnerships) or sole proprietorship: A general partner or the proprietor, respectively. If a general partner is a corporation, the provisions of paragraph (1) of this definition apply;

(3) For a municipality, state, Federal, or other public agency: Either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (*e.g.*, a Regional Administrator of EPA); or

(4) For affected facilities:

(i) The designated representative in so far as actions, standards, requirements, or prohibitions under title IV of the CAA or the regulations promulgated thereunder are concerned; or

(ii) The designated representative for any other purposes under this part.

Closed vent system means a system that is not open to the atmosphere and that is composed of hard-piping, ductwork, connections, and, if necessary, flow-inducing devices that transport gas or vapor from a piece or pieces of equipment to a control device or back to a process.

Coil tubing cleanout means the process where an operator runs a string of coil tubing to the packed proppant within a well and jets the well to dislodge the proppant and provide sufficient lift energy to flow it to the surface. Coil tubing cleanout includes mechanical methods to remove solids and/or debris from a wellbore.

Collection system means any infrastructure that conveys gas or liquids from the well site to another location for treatment, storage, processing, recycling, disposal or other handling.

Completion combustion device means any ignition device, installed horizontally or vertically, used in exploration and production operations to combust otherwise vented emissions from completions. Completion combustion devices include pit flares.

Compressor mode means the operational and pressurized status of a compressor. For both centrifugal compressors and reciprocating compressors, "mode" refers to either: Operating-mode, standby-pressurized-mode, or not-operating-depressurized-mode.

Compressor station means any permanent combination of one or more compressors that move natural gas at increased pressure through gathering or transmission pipelines, or into or out of storage. This includes but is not limited to gathering and boosting stations and transmission compressor stations. The combination of one or more compressors located at a well site, centralized production facility, or an onshore natural gas processing plant, is not a compressor station for purposes of § 60.5365b(e) and § 60.5397b.

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.

Connector means flanged, screwed, or other joined fittings used to connect two pipe lines or a pipe line and a piece of process equipment or that close an opening in a pipe that could be connected to another pipe. Joined fittings welded completely around the circumference of the interface are not considered connectors for the purpose of this regulation.

Continuous bleed means a continuous flow of pneumatic supply natural gas to a process controller.

Crude oil and natural gas source category means:

- (1) Crude oil production, which includes the well and extends to the point of custody transfer to the crude oil transmission pipeline or any other forms of transportation; and
- (2) Natural gas production, processing, transmission, and storage, which include the well and extend to, but do not include, the local distribution company custody transfer station.

Custody meter means the meter where natural gas or hydrocarbon liquids are measured for sales, transfers, and/or royalty determination.

Custody meter assembly means an assembly of fugitive emissions components, including the custody meter, valves, flanges, and connectors necessary for the proper operation of the custody meter.

Custody transfer means the transfer of crude oil or natural gas after processing and/or treatment in the producing operations, or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation.

Dehydrator means a device in which an absorbent directly contacts a natural gas stream and absorbs water in a contact tower or adsorption column (absorber).

Delineation well means a well drilled in order to determine the boundary of a field or producing reservoir.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

- (1) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard;
- (2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or
- (3) Fails to meet any emission limit, operating limit, or work practice standard of this subpart during startup, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

Distance piece means an open or enclosed casing through which the piston rod travels, separating the compressor cylinder from the crankcase.

Double block and bleed system means two block valves connected in series with a bleed valve or line that can vent the line between the two block valves.

Duct work means a conveyance system such as those commonly used for heating and ventilation systems. It is often made of sheet metal and often has sections connected by screw or crimping. Hard-piping is not ductwork.

Emergency shutdown device means a device which functions exclusively to protect personnel and/or prevent physical damage to equipment by shutting down equipment or gas flow during unsafe conditions resulting from an unexpected event, such as a pipe break or fire. For the purposes of this subpart, an emergency shutdown device is not used for routine control of operating conditions.

Equipment, as used in the standards and requirements of this subpart relative to the process unit equipment affected facility at onshore natural gas processing plants, means each pump, pressure relief device, open-ended valve or line, valve, and flange or other connector that has the potential to emit methane or VOC and any device or system required by those same standards and requirements of this subpart.

Field gas means feedstock gas entering the natural gas processing plant.

Field gas gathering means the system used transport field gas from a field to the main pipeline in the area.

First attempt at repair means an action taken for the purpose of stopping or reducing fugitive emissions to the atmosphere. First attempts at repair include, but are not limited to, the following practices where practicable and appropriate: Tightening bonnet bolts; replacing bonnet bolts; tightening packing gland nuts; or injecting lubricant into lubricated packing.

Flare means a thermal oxidation system using an open (without enclosure) flame. Completion combustion devices as defined in this section are not considered flares.

Flow line means a pipeline used to transport oil and/or gas to a processing facility or a mainline pipeline.

Flowback means the process of allowing fluids and entrained solids to flow from a well following a treatment, either in preparation for a subsequent phase of treatment or in preparation for cleanup and returning the well to production. The term flowback also means the fluids and entrained solids that emerge from a well during the flowback process. The flowback period begins when material introduced into the well during the treatment returns to the surface following hydraulic fracturing or refracturing. The flowback period ends when either the well is shut in and permanently disconnected from the flowback equipment or at the startup of production. The flowback period includes the initial flowback stage and the separation flowback stage. Screenouts, coil tubing cleanouts, and plug drill-outs are not considered part of the flowback process.

Fuel gas means gases that are combusted to derive useful work or heat.

Fuel gas system means the offsite and onsite piping and flow and pressure control system that gathers gaseous stream(s) generated by onsite operations, may blend them with other sources of gas, and transports the gaseous

stream for use as fuel gas in combustion devices or in-process combustion equipment, such as furnaces and gas turbines, either singly or in combination.

Fugitive emissions means, for the purposes of § 60.5397b, any indication of emissions observed from a fugitive emissions component using AVO, an indication of visible emissions observed from an OGI instrument, or an instrument reading of 500 ppmv or greater using Method 21 of appendix A-7 to this part.

Fugitive emissions component means any component that has the potential to emit fugitive emissions of methane or VOC at a well site, centralized production facility, or compressor station, such as valves (including separator dump valves), connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems not subject to § 60.5411b, thief hatches or other openings on a storage vessel not subject to § 60.5395b, compressors, instruments, meters, and yard piping.

Gas to oil ratio (GOR) means the ratio of the volume of gas at standard temperature and pressure that is produced from a volume of oil when depressurized to standard temperature and pressure.

Hard-piping means pipe or tubing that is manufactured and properly installed using good engineering judgment and standards such as ASME B31.3, Process Piping (available from the American Society of Mechanical Engineers, P.O. Box 2300, Fairfield, NJ 07007-2300).

Hydraulic fracturing means the process of directing pressurized fluids containing any combination of water, proppant, and any added chemicals to penetrate tight formations, such as shale or coal formations, that subsequently require high rate, extended flowback to expel fracture fluids and solids during completions.

Hydraulic refracturing means conducting a subsequent hydraulic fracturing operation at a well that has previously undergone a hydraulic fracturing operation.

In gas/vapor service means that the piece of equipment contains process fluid that is in the gaseous state at operating conditions.

In heavy liquid service means that the piece of equipment is not in gas/vapor service or in light liquid service.

In light liquid service means that the piece of equipment contains a liquid that meets the conditions specified in § 60.5402b(d)(2) or § 60.5403b.

In vacuum service means that equipment is operating at an internal pressure which is at least 5 kilopascals (kPa) (0.7 psia) below ambient pressure.

In wet gas service means that a compressor or piece of equipment contains or contacts the field gas before the extraction step at a gas processing plant process unit.

Initial calibration value as used in the standards and requirements of this subpart relative to the process unit equipment affected facility at onshore natural gas processing plants means the concentration measured during the initial calibration at the beginning of each day required in § 60.5403b, or the most recent calibration if the instrument is recalibrated during the day (*i.e.*, the calibration is adjusted) after a calibration drift assessment.

Initial flowback stage means the period during a well completion operation which begins at the onset of flowback and ends at the separation flowback stage.

Intermediate hydrocarbon liquid means any naturally occurring, unrefined petroleum liquid.

Intermittent vent natural gas-driven process controller means a process controller that is not designed to have a continuous bleed rate but is instead designed to only release natural gas to the atmosphere as part of the actuation cycle.

Liquefied natural gas unit means a unit used to cool natural gas to the point at which it is condensed into a liquid which is colorless, odorless, non-corrosive and non-toxic.

Liquid collection system means tankage and/or lines at a well site to contain liquids from one or more wells or to convey liquids to another site.

Liquids dripping means any visible leakage from the seal, including spraying, misting, clouding, and ice formation.

Liquids unloading means the unloading of liquids that have accumulated over time in gas wells, which are impeding or halting production. Routine well maintenance activities, including workovers, screenouts, coil tubing cleanouts, or any other activity that requires a rig or other machinery are not considered liquids unloading.

Local distribution company (LDC) custody transfer station means a metering station where the LDC receives a natural gas supply from an upstream supplier, which may be an interstate transmission pipeline or a local natural gas producer, for delivery to customers through the LDC's intrastate transmission or distribution lines.

Low-e valve means a valve (including its specific packing assembly) for which the manufacturer has issued a written warranty or performance guarantee that it will not emit fugitives at greater than 100 ppm in the first five years. A valve may qualify as a low-e valve if it is as an extension of another valve that has qualified as a low-e valve.

Low-e packing means a valve packing product for which the manufacturer has issued a written warranty or performance guarantee that it will not emit fugitives at greater than 100 ppm in the first five years. Low-e injectable packing is a type of low-e packing product for which the manufacturer has also issued a written warranty or performance guarantee and that can be injected into a valve during a "drill-and-tap" repair of the valve.

Low pressure well means a well that satisfies at least one of the following conditions:

- (1) The static pressure at the wellhead following fracturing but prior to the onset of flowback is less than the flow line pressure;
- (2) The pressure of flowback fluid immediately before it enters the flow line, as determined under § 60.5432b, is less than the flow line pressure; or
- (3) Flowback of the fracture fluids will not occur without the use of artificial lift equipment.

Major production and processing equipment means reciprocating or centrifugal compressors, glycol dehydrators, heater/treaters, separators, control devices, natural gas-driven process controllers, natural gas-driven pumps, and storage vessels or tank batteries collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water, for the purpose of determining whether a well site is a wellhead only well site.

Maximum average daily throughput means the following:

- (1) The earliest calculation of daily average throughput, determined as described in paragraph (2) or (3) of this definition, to a tank battery over the days that production is routed to that tank battery during the 30-day PTE evaluation period employing generally accepted methods specified in § 60.5365b(e)(2).
- (2) If throughput to the tank battery is measured on a daily basis (*e.g.*, via level gauge automation or daily manual gauging), the maximum average daily throughput is the average of all daily throughputs for days on which throughput was routed to the tank battery during the 30-day evaluation period; or
- (3) If throughput to the tank battery is not measured on a daily basis (*e.g.*, via manual gauging at the start and end of loadouts), the maximum average daily throughput is the highest, of the average daily throughputs, determined for any production period to that tank battery during the 30-day evaluation period, as determined by averaging total throughput to that tank battery over each production period. A production period begins when production begins to be routed to a tank battery and ends either when throughput is routed away from that tank battery or when a loadout occurs from that tank battery, whichever happens first. Regardless of the determination methodology, operators must not include days during which throughput is not routed to the tank battery when calculating maximum average daily throughput for that tank battery.

Multi-wellhead only well site means a well site that contains two or more wellheads and no major production and processing equipment.

Natural gas-driven diaphragm pump means a positive displacement pump powered by pressurized natural gas that uses the reciprocating action of flexible diaphragms in conjunction with check valves to pump a fluid. A pump in which a fluid is displaced by a piston driven by a diaphragm is not considered a diaphragm pump for purposes of this subpart. A lean glycol circulation pump that relies on energy exchange with the rich glycol from the contactor is not considered a diaphragm pump.

Natural gas-driven piston pump means a positive displacement pump powered by pressurized natural gas that moves and pressurizes fluid by using one or more reciprocating pistons. A pump in which a fluid is displaced by a piston driven by a diaphragm is considered a piston pump for purposes of this subpart. A lean glycol circulation pump that relies on energy exchange with the rich glycol from the contactor is not considered a piston pump.

Natural gas-driven process controller means a process controller powered by pressurized natural gas.

Natural gas liquids means the hydrocarbons, such as ethane, propane, butane, and pentane that are extracted from field gas.

Natural gas processing plant (gas plant) means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

Natural gas transmission means the pipelines used for the long-distance transport of natural gas (excluding processing). Specific equipment used in natural gas transmission includes the land, mains, valves, meters, boosters, regulators, storage vessels, dehydrators, compressors, and their driving units and appurtenances, and equipment used for transporting gas from a production plant, delivery point of purchased gas, gathering system, storage area, or other wholesale source of gas to one or more distribution area(s).

No detectable emissions means, for the purposes of § 60.5401b and § 60.5403b, that the equipment is operating with an instrument reading of less than 500 ppmv above background, as determined by Method 21 of appendix A-7 to this part.

No identifiable emissions means, for the purposes of covers, closed vent systems, and self-contained natural gas-driven process controllers and as determined according to the provisions of § 60.5416b, that no emissions are detected by AVO means when inspections are conducted by AVO; no emissions are imaged with an OGI camera when inspections are conducted with OGI; and equipment is operating with an instrument reading of less than 500 ppmv above background, as determined by Method 21 of appendix A-7 to this part when inspections are conducted with Method 21.

Nonfractionating plant means any gas plant that does not fractionate mixed natural gas liquids into natural gas products.

Non-natural gas-driven process controller means an instrument that is actuated using other sources of power than pressurized natural gas; examples include solar, electric, and instrument air.

Onshore means all facilities except those that are located in the territorial seas or on the outer continental shelf.

Open-ended valve or line or open-ended vent line means any valves, except safety relief valves, having one side of the valve seat in contact with process fluid and one side open to the atmosphere, either directly or through open piping.

Plug drill-out means the removal of a plug (or plugs) that was used to isolate different sections of the well.

Process controller means an automated instrument used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature.

Pressure release means the emission of materials resulting from system pressure being greater than set pressure of the pressure relief device.

Pressure vessel means a storage vessel that is used to store liquids or gases and is designed not to vent to the atmosphere as a result of compression of the vapor headspace in the pressure vessel during filling of the pressure vessel to its design capacity.

Pressurized mode means when the compressor contains natural gas that is maintained at a pressure higher than the atmospheric pressure.

Process improvement means routine changes made for safety and occupational health requirements, for energy savings, for better utility, for ease of maintenance and operation, for correction of design deficiencies, for bottleneck removal, for changing product requirements, or for environmental control.

Process unit means components assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.

Process unit shutdown means a work practice or operational procedure that stops production from a process unit or part of a process unit during which it is technically feasible to clear process material from a process unit or part of a process unit consistent with safety constraints and during which repairs can be accomplished. The following are not considered process unit shutdowns:

- (1) An unscheduled work practice or operational procedure that stops production from a process unit or part of a process unit for less than 24 hours.
- (2) An unscheduled work practice or operational procedure that would stop production from a process unit or part of a process unit for a shorter period of time than would be required to clear the process unit or part of the process unit of materials and start up the unit, and would result in greater emissions than delay of repair of leaking components until the next scheduled process unit shutdown.
- (3) The use of spare equipment and technically feasible bypassing of equipment without stopping production.

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.

Qualified Professional Engineer means an individual who is licensed by a state as a Professional Engineer to practice one or more disciplines of engineering and who is qualified by education, technical knowledge, and experience to make the specific technical certifications required under this subpart. Professional engineers making these certifications must be currently licensed in at least one state in which the certifying official is located.

Quarter means a 3-month period. For purposes of standards for process unit equipment affected facilities at onshore natural gas processing plants, the first quarter concludes on the last day of the last full month during the 180 days following initial startup.

Reciprocating compressor means a piece of equipment that increases the pressure of a process gas by positive displacement, employing linear movement of the driveshaft.

Reciprocating compressor rod packing means a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas that escapes to the atmosphere, or other mechanism that provides the same function.

Recovered gas means gas recovered through the separation process during flowback.

Recovered liquids means any crude oil, condensate or produced water recovered through the separation process during flowback.

Reduced emissions completion means a well completion following fracturing or refracturing where gas flowback that is otherwise vented is captured, cleaned, and routed to the gas flow line or collection system, re-injected into the well or another well, used as an onsite fuel source, or used for other useful purpose that a purchased fuel or raw material would serve, with no direct release to the atmosphere.

Reduced sulfur compounds means H₂S, carbonyl sulfide (COS), and carbon disulfide (CS₂).

Removed from service means that a storage vessel affected facility has been physically isolated and disconnected from the process for a purpose other than maintenance in accordance with § 60.5395b(c)(1).

Repaired means the following:

(1) For the purposes of fugitive emissions components affected facilities, that fugitive emissions components are adjusted, replaced, or otherwise altered, in order to eliminate fugitive emissions and resurveyed as specified in § 60.5397b(h)(4) and it is verified that emissions from the fugitive emissions components are below the applicable fugitive emissions definition.

(2) For the purposes of process unit equipment affected facilities, that equipment is adjusted, or otherwise altered, in order to eliminate a leak as defined in §§ 60.5400b and 60.5401b and is re-monitored as specified in § 60.5400b(b) introductory text and (b)(1) or § 60.5403b, respectively, to verify that emissions from the equipment are below the applicable leak definition. Pumps in light liquid service subject to § 60.5400b(c)(2) or § 60.5401b(b)(1)(ii) are not subject to re-monitoring.

Replacement cost means the capital needed to purchase all the depreciable components in a facility.

Returned to service means that a storage vessel affected facility that was removed from service has been:

(1) Reconnected to the original source of liquids or has been used to replace any storage vessel affected facility;
or

(2) Installed in any location covered by this subpart and introduced with crude oil, condensate, intermediate hydrocarbon liquids or produced water.

Routed to a process or route to a process means the emissions are conveyed via a closed vent system to any enclosed portion of a process that is operational where the emissions are predominantly recycled and/or consumed in the same manner as a material that fulfills the same function in the process and/or transformed by chemical reaction into materials that are not regulated materials and/or incorporated into a product; and/or recovered.

Salable quality gas means natural gas that meets the flow line or collection system operator specifications, regardless of whether such gas is sold.

Screenout means an attempt to clear proppant from the wellbore to dislodge the proppant out of the well.

Self-contained process controller means a natural gas-driven process controller that releases gas into the downstream piping and not to the atmosphere, resulting in zero methane and VOC emissions.

Self-contained wet seal centrifugal compressor means:

(1) A wet seal centrifugal compressor system that is a closed process that ports the degassing emissions into the natural gas line at the compressor suction (*i.e.*, degassed emissions are recovered) or which has an intermediate closed process that degasses most of the gas entrained in the seal oil and sends that gas to another process. The de-gas emissions are routed back to suction or process directly from the closed or intermediate closed degassing process; after the closed or intermediate closed degassing process the oil is ultimately recycled for recirculation in the seals to the lube oil tank where any small amount of residual gas is released through a vent.

(2) A wet seal centrifugal compressor equipped with mechanical wet seals, where

- (i) A differential pressure is maintained on the system and there is no off gassing of the lube oil, and
- (ii) The mechanical seal is integrated into the compressor housing.

Sensor means a device that measures a physical quantity or the change in a physical quantity such as temperature, pressure, flow rate, pH, or liquid level.

Separation flowback stage means the period during a well completion operation when it is technically feasible for a separator to function. The separation flowback stage ends either at the startup of production, or when the well is shut in and permanently disconnected from the flowback equipment.

Separator dump valve means, for purposes of the fugitive emission standards in §§ 60.5397b and 60.5398b, a liquid-control valve in a separator that controls the liquid level within the separator vessel.

Single wellhead only well site means a wellhead only well site that contains only one wellhead and no major production and processing equipment.

Small well site means, for purposes of the fugitive emissions standards in §§ 60.5397b and 60.5398b, a well site that contains a single wellhead, no more than one piece of certain major production and processing equipment, and associated meters and yard piping. Small well sites cannot include any controlled storage vessels (or controlled tank batteries), control devices, natural gas-driven process controllers, or natural gas-driven pumps.

Startup of production means the beginning of initial flow following the end of flowback when there is continuous recovery of salable quality gas and separation and recovery of any crude oil, condensate, or produced water, except as otherwise provided in this definition. For the purposes of the fugitive monitoring requirements of § 60.5397b, *startup of production* means the beginning of the continuous recovery of salable quality gas and separation and recovery of any crude oil, condensate, or produced water.

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. A well completion vessel that receives recovered liquids from a well after startup of production following flowback for a period which exceeds 60 days is considered a storage vessel under this subpart. A tank or other vessel shall not be considered a storage vessel if it has been removed from service in accordance with the requirements of § 60.5395b(c)(1) until such time as such tank or other vessel has been returned to service. 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 § 60.5420b(c)(7)(v), 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 from the date the original vessel was first located at the site. This exclusion does not apply to a well completion vessel as described above.
- (2) Process vessels such as surge control vessels, bottoms receivers or knockout vessels.
- (3) Pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere.

Sulfur production rate means the rate of liquid sulfur accumulation from the sulfur recovery unit.

Sulfur recovery unit means a process device that recovers element sulfur from acid gas.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Sweetening unit means a process device that removes hydrogen sulfide and/or carbon dioxide from the sour natural gas stream.

Tank battery means a group of all storage vessels that are manifolded together for liquid transfer. A tank battery may consist of a single storage vessel if only one storage vessel is present.

Total Reduced Sulfur (TRS) means the sum of the sulfur compounds hydrogen sulfide, methyl mercaptan, dimethyl sulfide, and dimethyl disulfide as measured by Method 16 of appendix A-6 to this part.

Total SO₂ equivalents means the sum of volumetric or mass concentrations of the sulfur compounds obtained by adding the quantity existing as SO₂ to the quantity of SO₂ that would be obtained if all reduced sulfur compounds were converted to SO₂ (ppmv or kg/dscm (lb/dscf)).

UIC Class I oilfield disposal well means a well with a UIC Class I permit that meets the definition in 40 CFR 144.6(a)(2) and receives eligible fluids from oil and natural gas exploration and production operations.

UIC Class II oilfield disposal well means a well with a UIC Class II permit where wastewater resulting from oil and natural gas production operations is injected into underground porous rock formations not productive of oil or gas, and sealed above and below by unbroken, impermeable strata.

Underground storage vessel means a storage vessel stored below ground.

Well means a hole drilled for the purpose of producing oil or natural gas, or a well into which fluids are injected.

Well completion means the process that allows for the flowback of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and tests the reservoir flow characteristics, which may vent produced hydrocarbons to the atmosphere via an open pit or tank.

Well completion operation means any well completion with hydraulic fracturing or refracturing occurring at a well completion affected facility.

Well completion vessel means a vessel that contains flowback during a well completion operation following hydraulic fracturing or refracturing. A well completion vessel may be a lined earthen pit, a tank or other vessel that is skid-mounted or portable. A well completion vessel that receives recovered liquids from a well after startup of production following flowback for a period which exceeds 60 days is considered a storage vessel under this subpart.

Well site means one or more surface sites that are constructed for the drilling and subsequent operation of any oil well, natural gas well, or injection well. For the purposes of the fugitive emissions standards at § 60.5397b, a well site does not include:

- (1) UIC Class II oilfield disposal wells and disposal facilities;
- (2) UIC Class I oilfield disposal wells; and
- (3) The flange immediately upstream of the custody meter assembly and equipment, including fugitive emissions components, located downstream of this flange.

Wellhead means the piping, casing, tubing and connected valves protruding above the earth's surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve. The wellhead does not include other equipment at the well site except for any conveyance through which gas is vented to the atmosphere.

Wellhead only well site means, for the purposes of the fugitive emissions standards at § 60.5397b and the standards in § 60.5398b, a well site that contains one or more wellheads and no major production and processing equipment.

Wildcat well means a well outside known fields or the first well drilled in an oil or gas field where no other oil and gas production exists.

Yard piping means hard-piping at a well site, centralized production facility, or compressor station that is not part of a closed vent system.

§ 60.5432b How do I determine whether a well is a low pressure well using the low pressure well equation?

(a) To determine that your well is a low pressure well subject to § 60.5375b(f), you must determine whether the characteristics of the well are such that the well meets the definition of low pressure well in § 60.5430b. To determine that the well meets the definition of low pressure well in § 60.5430b, you must use the low pressure well equation:

Equation 1 to paragraph (a)

$$P_L \text{ (psia)} = 0.495 \times P_R - \frac{q_g}{q_g + q_o + q_w} [0.05 \times P_R + 0.038 \times L - 67.578] - \left[\frac{q_o}{q_g + q_o + q_w} \times \frac{\rho_o}{144} + \frac{q_w}{q_g + q_o + q_w} 0.433 \right] \cdot L$$

Where:

- (1) P_L is the pressure of flowback fluid immediately before it enters the flow line, expressed in pounds force per square inch (psia), and is to be calculated using the equation above;
 - (2) P_R is the pressure of the reservoir containing oil, gas, and water at the well site, expressed in psia;
 - (3) L is the true vertical depth of the well, expressed in feet (ft);
 - (4) q_o is the flow rate of oil in the well, expressed in cubic feet/second (cu ft/sec);
 - (5) q_g is the flow rate of gas in the well, expressed in cu ft/sec;
 - (6) q_w is the flow rate of water in the well, expressed in cu ft/sec;
 - (7) ρ_o is the density of oil in the well, expressed in pounds mass per cubic feet (lbm/cu ft).
- (b) You must determine the four values in paragraphs (a)(4) through (7) of this section, using the calculations in paragraphs (b)(1) through (15) of this section.

- (1) Determine the value of the bottom hole pressure, P_{BH} (psia), based on available information at the well site, or by calculating it using the reservoir pressure, P_R (psia), in the following equation:

Equation 2 to paragraph (b)(1)

$$P_{BH} \text{ (psia)} = \frac{1}{2} P_R$$

- (2) Determine the value of the bottom hole temperature, T_{BH} (F), based on available information at the well site, or by calculating it using the true vertical depth of the well, L (ft), in the following equation:

Equation 3 paragraph (b)(2)

$$T_{BH} \text{ (F)} = (0.014 \times L) + 79.081$$

(3) Calculate the value of the applicable natural gas specific gravity that would result from a separator pressure of 100 psig, γ_{gs} , using the following equation with: Separator at standard conditions (pressure, $p = 14.7$ (psia), temperature, $T = 60$ (F)); the oil API gravity at the well site, γ_o ; and the gas specific gravity at the separator under standard conditions, $\gamma_{gp} = 0.75$:

Equation 4 to paragraph (bh)(3)

$$\gamma_{gs} = \gamma_{gp} \cdot \left(1.0 + 5.912 \times 10^{-5} \cdot \gamma_o \cdot T \cdot \log \left(\frac{p}{114.7} \right) \right)$$

(4) Calculate the value of the applicable dissolved GOR, R_s (scf/STBO), using the following equation with: The bottom hole pressure, P_{BH} (psia), determined in (b)(1) of this section; the bottom hole temperature, T_{BH} (F), determined in (b)(2) of this section; the gas gravity at separator pressure of 100 psig, γ_{gs} , calculated in (b)(3) of this section; the oil API gravity, γ_o , at the well site; and the constants, C1, C2, and C3, found in Table 1 to this paragraph(b)(4):

Equation 5 to paragraph (b)(4)

$$R_s \left(\frac{\text{scf}}{\text{STBO}} \right) = C1 \cdot \gamma_{gs} \cdot P_{BH}^{C2} \cdot \exp \left[C3 \left(\frac{\gamma_o}{T_{BH} + 460} \right) \right]$$

Table 1 to Paragraph (b)(4)—Coefficients for the Correlation for R_s

Constant	$\gamma_{API} \leq 30$	$\gamma_{API} > 30$
C1	0.0362	0.0178
C2	1.0937	1.1870
C3	25.7240	23.931

(5) Calculate the value of the oil formation volume factor, B_o (bbl/STBO), using the following equation with: The bottom hole temperature, T_{BH} (F), determined in paragraph (b)(2) of this section; the gas gravity at separator pressure of 100 psig, γ_{gs} , calculated in paragraph (b)(3) of this section; the dissolved GOR, R_s (scf/STBO), calculated in paragraph (b)(4) of this section; the oil API gravity, γ_o , at the well site; and the constants, C1, C2, and C3, found in Table 2 to this paragraph (b)(5):

Equation 6 to paragraph (b)(5)

$$B_o \left(\frac{\text{bbl}}{\text{STBO}} \right) = 1.0 + C1 \cdot R_s + (T_{BH} - 60) \left(\frac{\gamma_o}{\gamma_{gs}} \right) \cdot (C2 + C3 \cdot R_s)$$

Table 2 to Paragraph (b)(5)—Coefficients for the Correlation for B_o

Constant	$\gamma_{API} \leq 30$	$\gamma_{API} > 30$
C1	4.677×10^{-4}	4.670×10^{-4}

Table 2 to Paragraph (b)(5)—Coefficients for the Correlation for B_o

Constant	$\gamma_{API} \leq 30$	$\gamma_{API} > 30$
C2	1.751×10^{-5}	1.100×10^{-5}
C3	-1.811×10^{-8}	1.337×10^{-9}

(6) Calculate the density of oil at the wellhead,

$$\rho_{WH} \left(\frac{lbm}{cu\ ft} \right),$$

using the following equation with the value of the oil API gravity, γ_o , at the well site:

Equation 7 to paragraph (b)(6)

$$\rho_{WH} \left(\frac{lbm}{cu\ ft} \right) = \frac{141.5}{\gamma_o + 131.5} \times 62.4$$

(7) Calculate the density of oil at bottom hole conditions,

$$\rho_{BH} \left(\frac{lbm}{cu\ ft} \right),$$

using the following equation with: the dissolved GOR, R_s (scf/STBO), calculated in paragraph (b)(4) of this section; the oil formation volume factor, B_o (bbl/STBO), calculated in paragraph (b)(5) of this section; the oil density at the wellhead,

$$\rho_{WH} \left(\frac{lbm}{cu\ ft} \right),$$

calculated in paragraph (b)(6) of this section; and the dissolved gas gravity, $\gamma_{gd} = 0.77$:

Equation 8 to paragraph (b)(7)

$$\rho_{BH} \left(\frac{lbm}{cu\ ft} \right) = \frac{\rho_{WH} + 0.0136 \times R_s \times \gamma_{gd}}{B_o}$$

(8) Calculate the density of oil in the well,

$$\rho_o \left(\frac{lbm}{cu\ ft} \right),$$

using the following equation with the density of oil at the wellhead,

$$\rho_{WH} \left(\frac{lbm}{cu\ ft} \right),$$

calculated in paragraph (b)(6) of this section; and the density of oil at bottom hole conditions,

$$\rho_{BH} \left(\frac{lbm}{cu\ ft} \right),$$

calculated in paragraph (b)(7) of this section:

Equation 9 to paragraph (b)(8)

$$\rho_o \left(\frac{lbm}{cu\ ft} \right) = 0.5 \times (\rho_{WH} + \rho_{BH})$$

(9) Calculate the oil flow rate, q_o (cu ft/sec,) using the following equation with: the oil formation volume factor, Bo (bbl/STBO), as calculated in paragraph (b)(5) of this section; and the estimated oil production rate at the well head, Q_o (STBO/day):

Equation 10 to paragraph (b)(9)

$$q_o \left(\frac{cu\ ft}{sec} \right) = Q_o \left(\frac{STBO}{day} \right) \times Bo \left(\frac{bbl}{STBO} \right) \times 5.614 \left(\frac{cu\ ft}{bbl} \right) \times \frac{1}{24 \times 60 \times 60} \left(\frac{day}{sec} \right)$$

(10) Calculate the critical pressure, P_c (psia), and critical temperature, T_c (R), using the equations below with: Gas gravity at standard conditions (pressure, $P = 14.7$ (psia), temperature, $T = 60$ (F)), $\gamma = 0.75$; and where the mole fractions of nitrogen, carbon dioxide and hydrogen sulfide in the gas are $X_{N_2} = 0.168225$, $X_{CO_2} = 0.013163$, and $X_{H_2S} = 0.013680$, respectively:

$$P_c \text{ (psia)} = 678 - 50 \cdot (\gamma_g - 0.5) - 206.7 \cdot X_{N_2} + 440 \cdot X_{CO_2} + 606.7 \cdot X_{H_2S}$$

$$T_c \text{ (R)} = 326 + 315.7 \cdot (\gamma_g - 0.5) - 240 \cdot X_{N_2} - 88.3 \cdot X_{CO_2} + 133.3 \cdot X_{H_2S}$$

(11) Calculate reduced pressure, P_r , and reduced temperature, T_r , using the following equations with: the bottom hole pressure, P_{BH} , as determined in paragraph (b)(1) of this section; the bottom hole temperature, T_{BH} (F), as determined in paragraph (b)(2) of this section in the following equations:

Equation 11 to paragraph (b)(11)

$$P_r = \frac{P_{BH}}{P_c}$$

$$T_r = \frac{T_{BH} + 460}{T_c}$$

(12)

(i) Calculate the gas compressibility factor, Z , using the following equation with the reduced pressure, P_r , calculated in paragraph (b)(11) of this section:

Equation 12 to paragraph (b)(12)(i)

$$Z = A + \frac{(1 - A)}{e^B} + C \cdot p_r^D$$

(ii) The values for A, B, C, D in the above equation, are calculated using the following equations with the reduced pressure, P_r , and reduced temperature, T_r , calculated in paragraph (b)(11) of this section:

Equation 13 to paragraph (b)(12)(ii)

$$A = 1.39 \cdot (T_r - 0.92)^{0.5} - 0.36 \cdot T_r - 0.101$$

$$B = (0.62 - 0.23 \cdot T_r) \cdot P_r + \left(\frac{0.066}{(T_r - 0.86)} - 0.037 \right) \cdot P_r^2$$

$$+ \frac{0.32}{10^{9(T_r - 1)}} \cdot P_r^6$$

$$C = (0.132 - 0.32 \cdot \log(T_r))$$

$$D = 10^{0.3106 - 0.49T_r + 0.1824T_r^2}$$

(13) Calculate the gas formation volume factor,

$$B_g \left(\frac{\text{cuft}}{\text{scf}} \right),$$

using the bottom hole pressure, P_{BH} (psia), as determined in paragraph (b)(1) of this section; and the bottom hole temperature, T_{BH} (F), as determined in paragraph (b)(2) of this section:

Equation 14 to paragraph (b)(13)

$$B_g \left(\frac{\text{cuft}}{\text{scf}} \right) = 0.0283 \cdot \frac{Z \cdot (T_{BH} + 460)}{P_{BH}} \quad \text{O}$$

(14) Calculate the gas flow rate,

$$q_g \left(\frac{\text{cuft}}{\text{sec}} \right),$$

using the following equation with: the value of gas formation volume factor,

$$B_g \left(\frac{\text{cuft}}{\text{scf}} \right),$$

calculated in paragraph (b)(13) of this section; the estimated gas production rate, Q_g (scf/day); the estimated oil production rate, Q_o (STBO/day); and the dissolved GOR, R_s (scf/STBO), as calculated in paragraph (b)(4) of this section:

Equation 15 to paragraph (b)(14)

$$q_g \left(\frac{cf}{sec} \right) = (Q_g - R_s \cdot Q_o) \cdot B_g \cdot \frac{1}{24 \times 60 \times 60}$$

(15) Calculate the flow rate of water in the well, q_w (cu ft/sec), using the following equation with the water production rate Q_w (bbl/day) at the well site:

Equation 16 to paragraph (b)(15)

$$q_w \left(\frac{cf}{sec} \right) = Q_w \left(\frac{bbl}{day} \right) \times 5.614 \left(\frac{cf}{bbl} \right) \times \frac{1}{24 \times 60 \times 60} \left(\frac{day}{sec} \right)$$

§§ 60.5433b-60.5439b [Reserved]

Table 1 to Subpart OOOOb of Part 60—Alternative Technology Periodic Screening Frequency at Well Sites, Centralized Production Facilities, and Compressor Stations Subject to AVO Inspections With Quarterly OGI or EPA Method 21 Monitoring

Minimum screening frequency	Minimum detection threshold of screening technology * (kg/hr)
Quarterly	≤1
Bimonthly	≤2
Bimonthly + Annual OGI	≤10
Monthly	≤5
Monthly + Annual OGI	≤15
* Based on a probability of detection of 90%.	

Table 2 to Subpart OOOOb of Part 60—Alternative Technology Periodic Screening Frequency at Well Sites and Centralized Production Facilities Subject to AVO Inspections and/or Semiannual OGI or EPA Method 21 Monitoring

Minimum screening frequency	Minimum detection threshold of screening technology * (kg/hr)
Semiannual	≤1
Triannual	≤2
Triannual + Annual OGI	≤10
Quarterly	≤5
Quarterly + Annual OGI	≤15

Minimum screening frequency	Minimum detection threshold of screening technology * (kg/hr)
Bimonthly	≤15

* Based on a probability of detection of 90%

Table 3 to Subpart OOOOb of Part 60—Required Minimum Initial SO₂ Emission Reduction Efficiency (Z_i)

H ₂ S 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		
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 4 to Subpart OOOOb of Part 60—Required Minimum SO₂ Emission Reduction Efficiency (Z_c)

Table 4 to Subpart OOOOb of Part 60—Required Minimum SO ₂ Emission Reduction Efficiency (Z _c)				
H ₂ S 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		
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

Table 5 to Subpart OOOOb of Part 60—Applicability of General Provisions to Subpart OOOOb

General provisions citation	Subject of citation	Applies to subpart?	Explanation
§ 60.1	General applicability of the General Provisions	Yes	
§ 60.2	Definitions	Yes	Additional terms defined in § 60.5430b.
§ 60.3	Units and abbreviations	Yes	
§ 60.4	Address	Yes	
§ 60.5	Determination of	Yes	

General provisions citation	Subject of citation	Applies to subpart?	Explanation
	construction or modification		
§ 60.6	Review of plans	Yes	
§ 60.7	Notification and record keeping	Yes	Except that § 60.7 only applies as specified in §§ 60.5417b(c) and 60.5420b(a).
§ 60.8	Performance tests	Yes	Except that the format and submittal of performance test reports is described in § 60.5420b(b) and (d). Performance testing is required for control devices used on storage vessels, centrifugal compressors, wells, reciprocating compressors, process controllers, and pumps, as applicable, except that performance testing is not required for a control device used solely on pump(s).
§ 60.9	Availability of information	Yes	
§ 60.10	State authority	Yes	
§ 60.11	Compliance with standards and maintenance requirements	No	Requirements are specified in subpart OOOOb.
§ 60.12	Circumvention	Yes	
§ 60.13	Monitoring requirements	Yes	
§ 60.14	Modification	Yes	To the extent any provision in § 60.14 conflicts with specific provisions in subpart OOOOb, it is superseded by subpart OOOOb provisions.
§ 60.15	Reconstruction	Yes	Except that § 60.15(d) does not apply to wells (i.e., well completions, well liquids unloading, associated gas wells), process controllers, pumps, centrifugal compressors, reciprocating compressors, storage vessels, or fugitive emissions components affected facilities.
§ 60.16	Priority list	Yes	
§ 60.17	Incorporations by reference	Yes	
§ 60.18	General control device and work practice requirements	Yes	
§ 60.19	General notification	Yes	

Permit Issued: [month day, year]
Permit Expires: [month day, year]

General provisions citation	Subject of citation	Applies to subpart?	Explanation
	and reporting requirement		

Appendix F. 40 CFR Part 60, Subpart GG—Standards of Performance for Stationary Gas Turbines

§ 60.330 Applicability and designation of affected facility.

- (a) Except as provided for in paragraphs (c) through (e) of this section, the provisions of this subpart are applicable to the following affected facilities: All stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (10 million Btu) per hour, based on the lower heating value of the fuel fired.
- (b) Any facility under paragraph (a) of this section which commences construction, modification, or reconstruction after October 3, 1977, is subject to the requirements of this part except as provided in paragraphs (e) and (j) of § 60.332.
- (c) As an alternative to being subject to this subpart, the owner or operator of a stationary combustion turbine meeting the applicability of this subpart may petition the Administrator (in writing) to become subject to the requirements for modified units in subpart KKKKa of this part. If the Administrator grants the petition, the affected facility is no longer subject to this subpart and is subject to (unless the unit is modified or reconstructed in the future) the requirements for modified units in subpart KKKKa of this part. The Administrator can only grant the petition if it is determined that compliance with subpart KKKKa of this part would be equivalent to, or more stringent than, compliance with this subpart.
- (d) Stationary gas turbines subject to subpart Da, KKKK, or KKKKa of this part are not subject to this subpart.
- (e) A combustion turbine that is subject to this subpart and is not a “major source” or located at a “major source” (as that term is defined at 42 U.S.C. 7661 (2)) is exempt from the requirements of 42 U.S.C. 7661a(a).

§ 60.331 Definitions.

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

- (a) *Stationary gas turbine* means any simple cycle gas turbine, regenerative cycle gas turbine, or any gas turbine portion of a combined cycle steam/electric generating system that is not self-propelled. It may, however, be mounted on a vehicle for portability. Portable combustion turbines are excluded from the definition of “stationary combustion turbine,” and not regulated under this part, if the turbine meets the definition of “nonroad engine” under title II of the Clean Air Act and applicable regulations and is certified to meet emission standards promulgated pursuant to title II of the Clean Air Act, along with all related requirements.
- (b) *Simple cycle gas turbine* means any stationary gas turbine which does not recover heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine, or which does not recover heat from the gas turbine exhaust gases to heat water or generate steam.
- (c) *Regenerative cycle gas turbine* means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine.
- (d) *Combined cycle gas turbine* means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to heat water or generate steam.
- (e) *Emergency gas turbine* means any stationary gas turbine which operates as a mechanical or electrical power source only when the primary power source for a facility has been rendered inoperable by an emergency situation.
- (f) *Ice fog* means an atmospheric suspension of highly reflective ice crystals.
- (g) *ISO standard day conditions* means 288 degrees Kelvin (15 °C, 59 °F), 60 percent relative humidity, and 101.3 kilopascals (14.69 psi, 1 atm) pressure.
- (h) *Efficiency* means the gas turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output based on the lower heating value of the fuel.

- (i) *Peak load* means 100 percent of the manufacturer's design capacity of the gas turbine at ISO standard day conditions.
- (j) *Base load* means the load level at which a gas turbine is normally operated.
- (k) *Fire-fighting turbine* means any stationary gas turbine that is used solely to pump water for extinguishing fires.
- (l) *Turbines employed in oil/gas production or oil/gas transportation* means any stationary gas turbine used to provide power to extract crude oil/natural gas from the earth or to move crude oil/natural gas, or products refined from these substances through pipelines.
- (m)-(n) [Reserved]
- (o) *Garrison facility* means any permanent military installation.
- (p) *Gas turbine model* means a group of gas turbines having the same nominal air flow, combustor inlet pressure, combustor inlet temperature, firing temperature, turbine inlet temperature, and turbine inlet pressure.
- (q) *Electric utility stationary gas turbine* means any stationary gas turbine constructed for the purpose of supplying more than one-third of its potential electric output capacity to any utility power distribution system for sale.
- (r) *Emergency fuel* is a fuel fired by a gas turbine only during circumstances, such as natural gas supply curtailment or breakdown of delivery system, that make it impossible to fire natural gas in the gas turbine.
- (s) *Unit operating hour* means a clock hour during which any fuel is combusted in the affected unit. If the unit combusts fuel for the entire clock hour, it is considered to be a full unit operating hour. If the unit combusts fuel for only part of the clock hour, it is considered to be a partial unit operating hour.
- (t) *Excess emissions* means a specified averaging period over which either:
 - (1) The NO_x emissions are higher than the applicable emission limit in § 60.332;
 - (2) The total sulfur content of the fuel being combusted in the affected facility exceeds the limit specified in § 60.333; or
 - (3) The recorded value of a particular monitored parameter is outside the acceptable range specified in the parameter monitoring plan for the affected unit.
- (u) *Natural gas* means a fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Equivalents of this in other units are as follows: 0.068 weight percent total sulfur, 680 parts per million by weight (ppmw) total sulfur, and 338 parts per million by volume (ppmv) at 15.5 degrees Celsius total sulfur. Additionally, natural gas must be composed of at least 70 percent methane by volume and have a gross calorific value between 950 and 1100 British thermal units (Btu) per standard cubic foot. Unless refined to meet the definition of natural gas in this paragraph (u), natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.
- (v) *Duct burner* means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary gas turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a heat recovery steam generating unit.
- (w) *Lean premix stationary combustion turbine* means any stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture for combustion in the combustor. Mixing may occur before or in the combustion chamber. A unit which is capable of operating in both lean premix and diffusion flame modes is

considered a lean premix stationary combustion turbine when it is in the lean premix mode, and it is considered a diffusion flame stationary combustion turbine when it is in the diffusion flame mode.

(x) *Diffusion flame stationary combustion turbine* means any stationary combustion turbine where fuel and air are injected at the combustor and are mixed only by diffusion prior to ignition. A unit which is capable of operating in both lean premix and diffusion flame modes is considered a lean premix stationary combustion turbine when it is in the lean premix mode, and it is considered a diffusion flame stationary combustion turbine when it is in the diffusion flame mode.

(y) *Unit operating day* means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

§ 60.332 Standard for nitrogen oxides.

(a) On and after the date on which the performance test required by § 60.8 is completed, every owner or operator subject to the provisions of this subpart as specified in paragraphs (b), (c), and (d) of this section shall comply with one of the following, except as provided in paragraphs (e), (f), (g), (h), (i), (j), (k), and (l) of this section.

(1) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

$$STD = 0.0075 \frac{(14.4)}{Y} + F$$

where:

STD = allowable ISO corrected (if required as given in § 60.335(b)(1)) NO_x emission concentration (percent by volume at 15 percent oxygen and on a dry basis),

Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour, and

F = NO_x emission allowance for fuel-bound nitrogen as defined in paragraph (a)(4) of this section.

(2) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

$$STD = 0.0150 \frac{(14.4)}{Y} + F$$

where:

STD = allowable ISO corrected (if required as given in § 60.335(b)(1)) NO_x emission concentration (percent by volume at 15 percent oxygen and on a dry basis),

Y = manufacturer's rated heat rate at manufacturer's rated peak load (kilojoules per watt hour), or actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour, and

F = NO_x emission allowance for fuel-bound nitrogen as defined in paragraph (a)(4) of this section.

(3) The use of F in paragraphs (a)(1) and (2) of this section is optional. That is, the owner or operator may choose to apply a NO_x allowance for fuel-bound nitrogen and determine the appropriate F-value in accordance with paragraph (a)(4) of this section or may accept an F-value of zero.

(4) If the owner or operator elects to apply a NO_x emission allowance for fuel-bound nitrogen, F shall be defined according to the nitrogen content of the fuel during the most recent performance test required under § 60.8 as follows:

Fuel-bound nitrogen (percent by weight)	F (NO _x percent by volume)
$N \leq .015$	0
$0.015 < N \leq 0.1$	0.04 (N)
$0.1 < N \leq 0.25$	$0.004 + 0.0067(N - 0.1)$
$N > 0.25$	0.005

Where:

N = the nitrogen content of the fuel (percent by weight).

or:

Manufacturers may develop and submit to EPA custom fuel-bound nitrogen allowances for each gas turbine model they manufacture. These fuel-bound nitrogen allowances shall be substantiated with data and must be approved for use by the Administrator before the initial performance test required by § 60.8. Notices of approval of custom fuel-bound nitrogen allowances will be published in the Federal Register.

(b) Electric utility stationary gas turbines with a heat input at peak load greater than 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired shall comply with the provisions of paragraph (a)(1) of this section.

(c) Stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 million Btu/hour) but less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired, shall comply with the provisions of paragraph (a)(2) of this section.

(d) Stationary gas turbines with a manufacturer's rated base load at ISO conditions of 30 megawatts or less except as provided in § 60.332(b) shall comply with paragraph (a)(2) of this section.

(e) Stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 million Btu/hour) but less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired and that have commenced construction prior to October 3, 1982 are exempt from paragraph (a) of this section.

(f) Stationary gas turbines using water or steam injection for control of NO_x emissions are exempt from paragraph (a) of this section when ice fog is deemed a traffic hazard by the owner or operator of the gas turbine.

(g) Emergency gas turbines, military gas turbines for use in other than a garrison facility, military gas turbines installed for use as military training facilities, and firefighting gas turbines are exempt from paragraph (a) of this section.

(h) Stationary gas turbines engaged by manufacturers in research and development of equipment for both gas turbine emission control techniques and gas turbine efficiency improvements are exempt from paragraph (a) of this section on a case-by-case basis as determined by the Administrator.

(i) Exemptions from the requirements of paragraph (a) of this section will be granted on a case-by-case basis as determined by the Administrator in specific geographical areas where mandatory water restrictions are required by governmental agencies because of drought conditions. These exemptions will be allowed only while the mandatory water restrictions are in effect.

(j) Stationary gas turbines with a heat input at peak load greater than 107.2 gigajoules per hour that commenced construction, modification, or reconstruction between the dates of October 3, 1977, and January 27, 1982, and were required in the September 10, 1979, Federal Register (44 FR 52792) to comply with paragraph (a)(1) of this section, except electric utility stationary gas turbines, are exempt from paragraph (a) of this section.

(k) Stationary gas turbines with a heat input greater than or equal to 10.7 gigajoules per hour (10 million Btu/hour) when fired with natural gas are exempt from paragraph (a)(2) of this section when being fired with an emergency fuel.

(l) Regenerative cycle gas turbines with a heat input less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) are exempt from paragraph (a) of this section.

§ 60.333 Standard for sulfur dioxide.

Except as provided in paragraph (c) of this section, on and after the date on which the performance test required to be conducted by § 60.8 is completed, every owner or operator subject to the provisions of this subpart shall comply with one or the other of the following conditions in paragraphs (a) and (b) of this section:

(a) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine any gases which contain sulfur dioxide in excess of 0.015 percent by volume at 15 percent oxygen and on a dry basis; or

(b) No owner or operator subject to the provisions of this subpart shall burn in any stationary gas turbine any fuel which contains total sulfur in excess of 0.8 percent by weight (8000 ppmw).

(c) Stationary gas turbines subject to either subpart J or Ja of this part are not subject to the SO₂ standards in this subpart.

§ 60.334 Monitoring of operations.

(a) Except as provided in paragraph (b) of this section, the owner or operator of any stationary gas turbine subject to the provisions of this subpart and using water or steam injection to control NO_x emissions shall install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine.

(b) The owner or operator of any stationary gas turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and which uses water or steam injection to control NO_x emissions may, as an alternative to operating the continuous monitoring system described in paragraph (a) of this section, install, certify, maintain, operate, and quality-assure a continuous emission monitoring system (CEMS) consisting of NO_x and O₂ monitors. As an alternative, a CO₂ monitor may be used to adjust the measured NO_x concentrations to 15 percent O₂ by either converting the CO₂ hourly averages to equivalent O₂ concentrations using Equation F-14a or F-14b in appendix F to part 75 of this chapter and making the adjustments to 15 percent O₂, or by using the CO₂ readings directly to make the adjustments, as described in Method 20. If the option to use a CEMS is chosen, the CEMS shall be installed, certified, maintained and operated as follows:

(1) Each CEMS must be installed and certified according to PS 2 and 3 (for diluent) of 40 CFR part 60, appendix B, except the 7-day calibration drift is based on unit operating days, not calendar days. Appendix F, Procedure 1 is not required. The relative accuracy test audit (RATA) of the NO_x and diluent monitors may be performed individually or on a combined basis, *i.e.*, the relative accuracy tests of the CEMS may be performed either:

- (i) On a ppm basis (for NO_x) and a percent O₂ basis for oxygen; or
- (ii) On a ppm at 15 percent O₂ basis; or
- (iii) On a ppm basis (for NO_x) and a percent CO₂ basis (for a CO₂ monitor that uses the procedures in Method 20 to correct the NO_x data to 15 percent O₂).

(2) As specified in § 60.13(e)(2), during each full unit operating hour, each monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required to validate the hour.

(3) For purposes of identifying excess emissions, CEMS data must be reduced to hourly averages as specified in § 60.13(h).

- (i) For each unit operating hour in which a valid hourly average, as described in paragraph (b)(2) of this section, is obtained for both NO_x and diluent, the data acquisition and handling system must calculate and record the hourly NO_x emissions in the units of the applicable NO_x emission standard under § 60.332(a), *i.e.*, percent NO_x by volume, dry basis, corrected to 15 percent O₂ and International Organization for Standardization (ISO) standard conditions (if required as given in § 60.335(b)(1)). For any hour in which the hourly average O₂ concentration exceeds 19.0 percent O₂, a diluent cap value of 19.0 percent O₂ may be used in the emission calculations.
- (ii) A worst case ISO correction factor may be calculated and applied using historical ambient data. For the purpose of this calculation, substitute the maximum humidity of ambient air (H_o), minimum ambient temperature (T_a), and minimum combustor inlet absolute pressure (P_o) into the ISO correction equation.
- (iii) If the owner or operator has installed a NO_x CEMS to meet the requirements of part 75 of this chapter, and is continuing to meet the ongoing requirements of part 75, the CEMS may be used to meet the requirements of this section, except that the missing data substitution methodology provided for at subpart D of part 75, is not required for purposes of identifying excess emissions. Instead, periods of missing CEMS data are to be reported as monitor downtime in the excess emissions and monitoring performance report required in § 60.7(c). For affected units that are also regulated under part 75, the NO_x emission rate may be monitored using a NO_x diluent CEMS that is installed and certified in accordance with appendix A to part 75 and the QA program in appendix E to part 75, or the low mass emissions methodology in § 75.19 of this chapter.

(c) For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and which does not use steam or water injection to control NO_x emissions, the owner or operator may, but is not required to, for purposes of determining excess emissions, use a CEMS that meets the requirements of paragraph (b) of this section. Also, if the owner or operator has previously submitted and received EPA, State, or local permitting authority approval of a procedure for monitoring compliance with the applicable NO_x emission limit under § 60.332, that approved procedure may continue to be used.

(d) The owner or operator of any new turbine constructed after July 8, 2004, and which uses water or steam injection to control NO_x emissions may elect to use either the requirements in paragraph (a) of this section for continuous water or steam to fuel ratio monitoring or may use a NO_x CEMS installed, certified, operated, maintained, and quality-assured as described in paragraph (b) of this section.

(e) The owner or operator of any new turbine that commences construction after July 8, 2004, and which does not use water or steam injection to control NO_x emissions, may, but is not required to, elect to use a NO_x CEMS installed, certified, operated, maintained, and quality-assured as described in paragraph (b) of this section. Other acceptable monitoring approaches include periodic testing approved by EPA or the State or local permitting authority or continuous parameter monitoring as described in paragraph (f) of this section.

(f) The owner or operator of a new turbine that commences construction after July 8, 2004, which does not use water or steam injection to control NO_x emissions may, but is not required to, perform continuous parameter monitoring as follows:

(1) For a diffusion flame turbine without add-on selective catalytic reduction controls (SCR), the owner or operator shall define at least four parameters indicative of the unit's NO_x formation characteristics and shall monitor these parameters continuously.

(2) For any lean premix stationary combustion turbine, the owner or operator shall continuously monitor the appropriate parameters to determine whether the unit is operating in low-NO_x mode.

(3) For any turbine that uses SCR to reduce NO_x emissions, the owner or operator shall continuously monitor appropriate parameters to verify the proper operation of the emission controls.

(4) For affected units that are also regulated under part 75 of this chapter, if the owner or operator elects to monitor NO_x emission rate using the methodology in appendix E to part 75 of this chapter, or the low mass emissions methodology in § 75.19 of this chapter, the requirements of this paragraph (f) may be met by performing the parametric monitoring described in section 2.3 of appendix E or in § 75.19(c)(1)(iv)(H) of this chapter.

(g) The steam or water to fuel ratio or other parameters that are continuously monitored as described in paragraphs (a), (d) or (f) of this section shall be monitored during the performance test required under § 60.8, to establish acceptable values and ranges. The owner or operator may supplement the performance test data with engineering analyses, design specifications, manufacturer's recommendations and other relevant information to define the acceptable parametric ranges more precisely. The owner or operator shall develop and keep on-site a parameter monitoring plan which explains the procedures used to document proper operation of the NO_x emission controls. The plan shall include the parameter(s) monitored and the acceptable range(s) of the parameter(s) as well as the basis for designating the parameter(s) and acceptable range(s). Any supplemental data such as engineering analyses, design specifications, manufacturer's recommendations and other relevant information shall be included in the monitoring plan. For affected units that are also subject to part 75 of this chapter and that use the low mass emissions methodology in § 75.19 of this chapter or the NO_x emission measurement methodology in appendix E to part 75, the owner or operator may meet the requirements of this paragraph by developing and keeping on-site (or at a central location for unmanned facilities) a quality-assurance plan, as described in § 75.19 (e)(5) or in section 2.3 of appendix E and section 1.3.6 of appendix B to part 75 of this chapter.

(h) The owner or operator of any stationary gas turbine subject to the provisions of this subpart:

(1) Shall monitor the total sulfur content of the fuel being fired in the turbine, except as provided in paragraph (h)(3) of this section. The sulfur content of the fuel must be determined using total sulfur methods described in § 60.335(b)(10). Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than 0.4 weight percent (4,000 ppmw), ASTM D4084-82, D4084-94, D5504-01, D6228-98, or Gas Processors Association Standard 2377-86 (all of which are incorporated by reference, see § 60.17), which measure the major sulfur compounds may be used; and

(2) Shall monitor the nitrogen content of the fuel combusted in the turbine, if the owner or operator claims an allowance for fuel bound nitrogen (*i.e.*, if an F-value greater than zero is being or will be used by the owner or

operator to calculate STD in § 60.332). The nitrogen content of the fuel shall be determined using methods described in § 60.335(b)(9) or an approved alternative.

(3) Notwithstanding the provisions of paragraph (h)(1) of this section, the owner or operator may elect not to monitor the total sulfur content of the gaseous fuel combusted in the turbine, if the gaseous fuel is demonstrated to meet the definition of natural gas in § 60.331(u), regardless of whether an existing custom schedule approved by the administrator for subpart GG requires such monitoring. The owner or operator shall use one of the following sources of information to make the required demonstration:

- (i) The gas quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel is 20.0 grains/100 scf or less; or
- (ii) Representative fuel sampling data which show that the sulfur content of the gaseous fuel does not exceed 20 grains/100 scf. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to part 75 of this chapter is required.

(4) For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and for which a custom fuel monitoring schedule has previously been approved, the owner or operator may, without submitting a special petition to the Administrator, continue monitoring on this schedule.

(i) The frequency of determining the sulfur and nitrogen content of the fuel shall be as follows:

(1) *Fuel oil.* For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of appendix D to part 75 of this chapter (*i.e.*, flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank). If an emission allowance is being claimed for fuel-bound nitrogen, the nitrogen content of the oil shall be determined and recorded once per unit operating day.

(2) *Gaseous fuel.* Any applicable nitrogen content value of the gaseous fuel shall be determined and recorded once per unit operating day. For owners and operators that elect not to demonstrate sulfur content using options in paragraph (h)(3) of this section, and for which the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel shall be determined and recorded once per unit operating day.

(3) *Custom schedules.* Notwithstanding the requirements of paragraph (i)(2) of this section, operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (i)(3)(i) and (i)(3)(ii) of this section, custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in § 60.333.

(i) The two custom sulfur monitoring schedules set forth in paragraphs (i)(3)(i)(A) through (D) and in paragraph (i)(3)(ii) of this section are acceptable, without prior Administrative approval:

(A) The owner or operator shall obtain daily total sulfur content measurements for 30 consecutive unit operating days, using the applicable methods specified in this subpart. Based on the results of the 30 daily samples, the required frequency for subsequent monitoring of the fuel's total sulfur content shall be as specified in paragraph (i)(3)(i)(B), (C), or (D) of this section, as applicable.

(B) If none of the 30 daily measurements of the fuel's total sulfur content exceeds 0.4 weight percent (4000 ppmw), subsequent sulfur content monitoring may be performed at 12 month intervals. If any of the samples taken at 12-month intervals has a total sulfur content between

0.4 and 0.8 weight percent (4000 and 8000 ppmw), follow the procedures in paragraph (i)(3)(i)(C) of this section. If any measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section.

(C) If at least one of the 30 daily measurements of the fuel's total sulfur content is between 0.4 and 0.8 weight percent (4000 and 8000 ppmw), but none exceeds 0.8 weight percent (8000 ppmw), then:

(1) Collect and analyze a sample every 30 days for three months. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, follow the procedures in paragraph (i)(3)(i)(C)(2) of this section.

(2) Begin monitoring at 6-month intervals for 12 months. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, follow the procedures in paragraph (i)(3)(i)(C)(3) of this section.

(3) Begin monitoring at 12-month intervals. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, continue to monitor at this frequency.

(D) If a sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), immediately begin daily monitoring according to paragraph (i)(3)(i)(A) of this section. Daily monitoring shall continue until 30 consecutive daily samples, each having a sulfur content no greater than 0.8 weight percent (8000 ppmw), are obtained. At that point, the applicable procedures of paragraph (i)(3)(i)(B) or (C) of this section shall be followed.

(ii) The owner or operator may use the data collected from the 720-hour sulfur sampling demonstration described in section 2.3.6 of appendix D to part 75 of this chapter to determine a custom sulfur sampling schedule, as follows:

(A) If the maximum fuel sulfur content obtained from the 720 hourly samples does not exceed 20 grains/100 scf (*i.e.*, the maximum total sulfur content of natural gas as defined in § 60.331(u)), no additional monitoring of the sulfur content of the gas is required, for the purposes of this subpart.

(B) If the maximum fuel sulfur content obtained from any of the 720 hourly samples exceeds 20 grains/100 scf, but none of the sulfur content values (when converted to weight percent sulfur) exceeds 0.4 weight percent (4000 ppmw), then the minimum required sampling frequency shall be one sample at 12 month intervals.

(C) If any sample result exceeds 0.4 weight percent sulfur (4000 ppmw), but none exceeds 0.8 weight percent sulfur (8000 ppmw), follow the provisions of paragraph (i)(3)(i)(C) of this section.

(D) If the sulfur content of any of the 720 hourly samples exceeds 0.8 weight percent (8000 ppmw), follow the provisions of paragraph (i)(3)(i)(D) of this section.

(j) For each affected unit that elects to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content or fuel nitrogen content under this subpart, the owner or operator shall submit reports of excess emissions and monitor downtime, in accordance with § 60.7(c). Excess emissions shall be reported for all periods of unit operation, including startup, shutdown and malfunction. For the purpose of reports required under § 60.7(c), periods of excess emissions and monitor downtime that shall be reported are defined as follows:

(1) Nitrogen oxides.

(i) For turbines using water or steam to fuel ratio monitoring:

(A) An excess emission shall be any unit operating hour for which the average steam or water to fuel ratio, as measured by the continuous monitoring system, falls below the acceptable steam or water to fuel ratio needed to demonstrate compliance with § 60.332, as established during the performance test required in § 60.8. Any unit operating hour in which no water or steam is injected into the turbine shall also be considered an excess emission.

(B) A period of monitor downtime shall be any unit operating hour in which water or steam is injected into the turbine, but the essential parametric data needed to determine the steam or water to fuel ratio are unavailable or invalid.

(C) Each report shall include the average steam or water to fuel ratio, average fuel consumption, ambient conditions (temperature, pressure, and humidity), gas turbine load, and (if applicable) the nitrogen content of the fuel during each excess emission. You do not have to report ambient conditions if you opt to use the worst case ISO correction factor as specified in § 60.334(b)(3)(ii), or if you are not using the ISO correction equation under the provisions of § 60.335(b)(1).

(ii) If the owner or operator elects to take an emission allowance for fuel bound nitrogen, then excess emissions and periods of monitor downtime are as described in paragraphs (j)(1)(ii)(A) and (B) of this section.

(A) An excess emission shall be the period of time during which the fuel-bound nitrogen (N) is greater than the value measured during the performance test required in § 60.8 and used to determine the allowance. The excess emission begins on the date and hour of the sample which shows that N is greater than the performance test value, and ends with the date and hour of a subsequent sample which shows a fuel nitrogen content less than or equal to the performance test value.

(B) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour that a required sample is taken, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

(iii) For turbines using NO_x and diluent CEMS:

(A) An hour of excess emissions shall be any unit operating hour in which the 4-hour rolling average NO_x concentration exceeds the applicable emission limit in § 60.332(a)(1) or (2). For the purposes of this subpart, a "4-hour rolling average NO_x concentration" is the arithmetic average of the average NO_x concentration measured by the CEMS for a given hour (corrected to 15 percent O₂ and, if required under § 60.335(b)(1), to ISO standard conditions) and the three unit operating hour average NO_x concentrations immediately preceding that unit operating hour.

(B) A period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour, for either NO_x concentration or diluent (or both).

(C) Each report shall include the ambient conditions (temperature, pressure, and humidity) at the time of the excess emission period and (if the owner or operator has claimed an emission allowance for fuel bound nitrogen) the nitrogen content of the fuel during the period of excess emissions. You do not have to report ambient conditions if you opt to use the worst case ISO correction factor as specified in § 60.334(b)(3)(ii), or if you are not using the ISO correction equation under the provisions of § 60.335(b)(1).

(iv) For owners or operators that elect, under paragraph (f) of this section, to monitor combustion parameters or parameters that document proper operation of the NO_x emission controls:

(A) An excess emission shall be a 4-hour rolling unit operating hour average in which any monitored parameter does not achieve the target value or is outside the acceptable range defined in the parameter monitoring plan for the unit.

(B) A period of monitor downtime shall be a unit operating hour in which any of the required parametric data are either not recorded or are invalid.

(2) Sulfur dioxide. If the owner or operator is required to monitor the sulfur content of the fuel under paragraph (h) of this section:

(i) For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 weight percent and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(ii) If the option to sample each delivery of fuel oil has been selected, the owner or operator shall immediately switch to one of the other oil sampling options (*i.e.*, daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.8 weight percent. The owner or operator shall continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and shall evaluate excess emissions according to paragraph (j)(2)(i) of this section. When all of the fuel from the delivery has been burned, the owner or operator may resume using the as-delivered sampling option.

(iii) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime shall include only unit operating hours, and ends on the date and hour of the next valid sample.

(3) *Ice fog*. Each period during which an exemption provided in § 60.332(f) is in effect shall be reported in writing to the Administrator in the semiannual report described in paragraph (k)(3) of this section. For each period, the ambient conditions existing during the period, the date and time the air pollution control system was deactivated, and the date and time the air pollution control system was reactivated shall be reported.

(4) *Emergency fuel*. Each period during which an exemption provided in § 60.332(k) is in effect shall be included in the report required in § 60.7(c). For each period, the type, reasons, and duration of the firing of the emergency fuel shall be reported.

(5) All reports required under § 60.7(c) shall be postmarked by the 30th day following the end of each 6-month period.

(k) The reporting requirements for this subpart shall be as follows:

(1) *Reporting frequency*. All reports required under § 60.7(c) must be electronically submitted via the Compliance and Emissions Data Reporting Interface (CEDRI) by the 30th day following the end of each 6-month period.

(2) *Electronic reporting*. Beginning on March 16, 2026, within 60 days after the date of completing each performance test or CEMS performance evaluation that includes a RATA, you must submit the results following the procedures specified in paragraph (k)(4) of this section. You must submit the report in a file format generated using the EPA's Electronic Reporting Tool (ERT). Alternatively, you may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website (<https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert>) accompanied by the other information required by § 60.8(f)(2) in PDF format.

(3) *General reporting requirements.* You must submit to the Administrator semiannual reports of the following recorded information. Beginning on January 15, 2027, or once the report template for this subpart has been available on the CEDRI website (<https://www.epa.gov/electronic-reporting-air-emissions/cedri>) for one year, whichever date is later, submit all subsequent reports using the appropriate electronic report template on the CEDRI website for this subpart and following the procedure specified in paragraph (k)(4) of this section. The date report templates become available will be listed on the CEDRI website. Unless the Administrator or delegated State agency or other authority has approved a different schedule for submission of reports, the report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted.

(4) *CEDRI and CBI.* If you are required to submit notifications or reports following the procedure specified in this paragraph (k)(4), you must submit notifications or reports to the EPA via CEDRI, which can be accessed through the EPA's Central Data Exchange (CDX) (<https://cdx.epa.gov/>). The EPA will make all the information submitted through CEDRI available to the public without further notice to you. Do not use CEDRI to submit information you claim as CBI. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim for some of the information in the report or notification, you must submit a complete file in the format specified in this subpart, including information claimed to be CBI, to the EPA following the procedures in paragraphs (k)(4)(i) and (ii) of this section. Clearly mark the part or all of the information that you claim to be CBI. Information not marked as CBI may be authorized for public release without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. All CBI claims must be asserted at the time of submission. Anything submitted using CEDRI cannot later be claimed CBI. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available. You must submit the same file submitted to the CBI office with the CBI omitted to the EPA via the EPA's CDX as described earlier in this paragraph (k)(4).

(i) The preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol, or other online file sharing services. Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address oaqps_cbi@epa.gov, and as described above, should include clear CBI markings. ERT files should be flagged to the attention of the Group Leader, Measurement Policy Group; all other files should be flagged to the attention of the Stationary Combustion Turbine Sector Lead. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if you do not have your own file sharing service, please email oaqps_cbi@epa.gov to request a file transfer link.

(ii) If you cannot transmit the file electronically, you may send CBI information through the postal service to the following address: U.S. EPA, Attn: OAQPS Document Control Office, Mail Drop: C404-02, 109 T.W. Alexander Drive, P.O. Box 12055, RTP, NC 27711. In addition to the OAQPS Document Control Officer, ERT files should also be sent to the attention of the Group Leader, Measurement Policy Group, and all other files should also be sent to the attention of the Stationary Combustion Turbine Sector Lead. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

(5) *System outage.* If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of EPA system outage for failure to timely comply with that reporting requirement. To assert a claim of EPA system outage, you must meet the requirements outlined in paragraphs (k)(5)(i) through (vii) of this section.

(i) You must have been or will be precluded from accessing CEDRI and submitting a required report within the time prescribed due to an outage of either the EPA's CEDRI or CDX systems.

(ii) The outage must have occurred within the period of time beginning 5 business days prior to the date that the submission is due.

(iii) The outage may be planned or unplanned.

(iv) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(v) You must provide to the Administrator a written description identifying:

(A) The date(s) and time(s) when CDX or CEDRI was accessed and the system was unavailable;

(B) A rationale for attributing the delay in reporting beyond the regulatory deadline to EPA system outage;

(C) A description of measures taken or to be taken to minimize the delay in reporting; and

(D) The date by which you propose to report, or if you have already met the reporting requirement at the time of notification, the date you reported.

(vi) The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(vii) In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved.

(6) *Force majeure*. If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of *force majeure* for failure to timely comply with that reporting requirement. To assert a claim of *force majeure*, you must meet the requirements outlined in paragraphs (k)(6)(i) through (v) of this section.

(i) You may submit a claim if a *force majeure* event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning five business days prior to the date the submission is due. For the purposes of this section, a *force majeure* event is defined as an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents you from complying with the requirement to submit a report electronically within the time period prescribed. Examples of such events are acts of nature (e.g., hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility (e.g., large scale power outage).

(ii) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(iii) You must provide to the Administrator:

(A) A written description of the *force majeure* event;

(B) A rationale for attributing the delay in reporting beyond the regulatory deadline to the *force majeure* event;

(C) A description of measures taken or to be taken to minimize the delay in reporting; and

(D) The date by which you propose to report, or if you have already met the reporting requirement at the time of notification, the date you reported.

(iv) The decision to accept the claim of *force majeure* and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(v) In any circumstance, the reporting must occur as soon as possible after the *force majeure* event occurs.

(7) *Record availability.* Any records required to be maintained by this subpart that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to a delegated air agency or the EPA as part of an on-site compliance evaluation.

§ 60.335 Test methods and procedures.

(a) The owner or operator shall conduct the performance tests required in § 60.8, using either

(1) EPA Method 20,

(2) ASTM D6522-00 (incorporated by reference, see § 60.17), or

(3) To determine NO_x and diluent concentration:

(i) Either EPA Method 7E in appendix A-4 to this part or EPA Method 320 in appendix A to part 63 of this chapter; and

(ii) Either EPA Method 3 or 3A in appendix A to this part.

(4) Sampling traverse points are to be selected following Method 20 or Method 1, (non-particulate procedures) and sampled for equal time intervals. The sampling shall be performed with a traversing single-hole probe or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

(5) Notwithstanding paragraph (a)(4) of this section, the owner or operator may test at few points than are specified in Method 1 or Method 20 if the following conditions are met:

(i) You may perform a stratification test for NO_x and diluent pursuant to

(A) [Reserved]

(B) The procedures specified in section 6.5.6.1(a) through (e) appendix A to part 75 of this chapter.

(ii) Once the stratification sampling is completed, the owner or operator may use the following alternative sample point selection criteria for the performance test:

(A) If each of the individual traverse point NO_x concentrations, normalized to 15 percent O₂, is within ±10 percent of the mean normalized concentration for all traverse points, then you may use 3 points (located either 16.7, 50.0, and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall). The 3 points shall be located along the measurement line that exhibited the highest average normalized NO_x concentration during the stratification test; or

(B) If each of the individual traverse point NO_x concentrations, normalized to 15 percent O₂, is within ±5 percent of the mean normalized concentration for all traverse points, then you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid.

(6) Other acceptable alternative reference methods and procedures are given in paragraph (c) of this section.

(b) The owner or operator shall determine compliance with the applicable nitrogen oxides emission limitation in § 60.332 and shall meet the performance test requirements of § 60.8 as follows:

(1) For each run of the performance test, the mean nitrogen oxides emission concentration (NO_{xo}) corrected to 15 percent O_2 shall be corrected to ISO standard conditions using the following equation. Notwithstanding this requirement, use of the ISO correction equation is optional for: Lean premix stationary combustion turbines; units used in association with heat recovery steam generators (HRSG) equipped with duct burners; and units equipped with add-on emission control devices:

$$\text{NO}_x = (\text{NO}_{\text{xo}})(P_r/P_o)^{0.5} e^{19(H_o - 0.00633)} (288^\circ\text{K}/T_a)^{1.53}$$

Where:

NO_x = emission concentration of NO_x at 15 percent O_2 and ISO standard ambient conditions, ppm by volume, dry basis,

NO_{xo} = mean observed NO_x concentration, ppm by volume, dry basis, at 15 percent O_2 ,

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,

H_o = observed humidity of ambient air, g H_2O /g air,

e = transcendental constant, 2.718, and

T_a = ambient temperature, $^\circ\text{K}$.

(2) The 3-run performance test required by § 60.8 must be performed within ± 5 percent at 30, 50, 75, and 90-to-100 percent of peak load or at four evenly-spaced load points in the normal operating range of the gas turbine, including the minimum point in the operating range and 90-to-100 percent of peak load, or at the highest achievable load point if 90-to-100 percent of peak load cannot be physically achieved in practice. If the turbine combusts both oil and gas as primary or backup fuels, separate performance testing is required for each fuel. Notwithstanding these requirements, performance testing is not required for any emergency fuel (as defined in § 60.331).

(3) For a combined cycle turbine system with supplemental heat (duct burner), the owner or operator may elect to measure the turbine NO_x emissions after the duct burner rather than directly after the turbine. If the owner or operator elects to use this alternative sampling location, the applicable NO_x emission limit in § 60.332 for the combustion turbine must still be met.

(4) If water or steam injection is used to control NO_x with no additional post-combustion NO_x control and the owner or operator chooses to monitor the steam or water to fuel ratio in accordance with § 60.334(a), then that monitoring system must be operated concurrently with each EPA Method 20, ASTM D6522-00 (incorporated by reference, see § 60.17), or EPA Method 7E run and shall be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable § 60.332 NO_x emission limit.

(5) If the owner operator elects to claim an emission allowance for fuel bound nitrogen as described in § 60.332, then concurrently with each reference method run, a representative sample of the fuel used shall be collected and analyzed, following the applicable procedures described in § 60.335(b)(9). These data shall be used to determine the maximum fuel nitrogen content for which the established water (or steam) to fuel ratio will be valid.

(6) If the owner or operator elects to install a CEMS, the performance evaluation of the CEMS may either be conducted separately (as described in paragraph (b)(7) of this section) or as part of the initial performance test of the affected unit.

(7) If the owner or operator elects to install and certify a NO_x CEMS under § 60.334(e), then the initial performance test required under § 60.8 may be done in the following alternative manner:

(i) Perform a minimum of 9 reference method runs, with a minimum time per run of 21 minutes, at a single load level, between 90 and 100 percent of peak (or the highest physically achievable) load while the source is combusting the fuel that is a normal primary fuel for that source.

(ii) Use the test data both to demonstrate compliance with the applicable NO_x emission limit under § 60.332 and to provide the required reference method data for the RATA of the CEMS described under § 60.334(b).

(iii) The requirement to test at three additional load levels is waived.

(8) If the owner or operator elects under § 60.334(f) to monitor combustion parameters or parameters indicative of proper operation of NO_x emission controls, the appropriate parameters shall be continuously monitored and recorded during each run of the initial performance test, to establish acceptable operating ranges, for purposes of the parameter monitoring plan for the affected unit, as specified in § 60.334(g).

(9) To determine the fuel bound nitrogen content of fuel being fired (if an emission allowance is claimed for fuel bound nitrogen), the owner or operator may use equipment and procedures meeting the requirements of:

(i) For liquid fuels, ASTM D2597-94 (Reapproved 1999), D6366-99, D4629-02, D5762-02 (all of which are incorporated by reference, see § 60.17); or

(ii) For gaseous fuels, shall use analytical methods and procedures that are accurate within ±5 percent of the instrument range and are approved by the Administrator.

(10) If the owner or operator is required under § 60.334(i)(1) or (3) to periodically determine the sulfur content of the fuel combusted in the turbine, a minimum of three fuel samples shall be collected during the performance test. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129-00, D2622-98, D4294-02, D1266-98, D5453-00 or D1552-01 (all of which are incorporated by reference, see § 60.17); or

(ii) For gaseous fuels, ASTM D1072-80, D1072-90 (Reapproved 1994); D3246-81, D3246-92, D3246-96; D4468-85 (Reapproved 2000); or D6667-01 (all of which are incorporated by reference, see § 60.17). The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the prior approval of the Administrator.

(11) The fuel analyses required under paragraphs (b)(9) and (b)(10) of this section may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency.

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

(1) Instead of using the equation in paragraph (b)(1) of this section, manufacturers may develop ambient condition correction factors to adjust the nitrogen oxides emission level measured by the performance test as provided in § 60.8 to ISO standard day conditions.

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