



# INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

*We Protect Hoosiers and Our Environment.*

100 N. Senate Avenue • Indianapolis, IN 46204

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Eric J. Holcomb  
Governor

Brian C. Rockensuess  
Commissioner

## Part 70 Operating Permit Renewal OFFICE OF AIR QUALITY

### Duke Energy Indiana, LLC - Cayuga Generating Station 3300 N SR 63 Cayuga, Indiana 47928

(herein known as the Permittee) is hereby authorized to operate subject to the conditions contained herein, the source described in Section A (Source Summary) of this permit.

**The Permittee must comply with all conditions of this permit. Noncompliance with any provisions of this permit is grounds for enforcement action; permit termination, revocation and reissuance, or modification; or denial of a permit renewal application. Noncompliance with any provision of this permit, except any provision specifically designated as not federally enforceable, constitutes a violation of the Clean Air Act. It shall not be a defense for the Permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit. An emergency does constitute an affirmative defense in an enforcement action provided the Permittee complies with the applicable requirements set forth in Section B, Emergency Provisions.**

This permit is issued in accordance with 326 IAC 2 and 40 CFR Part 70 Appendix A and contains the conditions and provisions specified in 326 IAC 2-7 as required by 42 U.S.C. 7401, et. seq. (Clean Air Act as amended by the 1990 Clean Air Act Amendments), 40 CFR Part 70.6, IC 13-15 and IC 13-17.

Operation Permit No.: T165-47094-00001	
Master Agency Interest ID: 11825	
Issued by:	Issuance Date:
Ghassan Shalabi, Section Chief Permits Branch Office of Air Quality	Expiration Date:

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**Attachment E: 40 CFR 63, Subpart UUUUU - National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units**

**Attachment F: 40 CFR Part 63, Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial and Institutional Boilers and Process Heaters**

## SECTION A SOURCE SUMMARY

This permit is based on information requested by the Indiana Department of Environmental Management (IDEM), Office of Air Quality (OAQ). The information describing the source contained in conditions A.1 through A.4 is descriptive information and does not constitute enforceable conditions. However, the Permittee should be aware that a physical change or a change in the method of operation that may render this descriptive information obsolete or inaccurate may trigger requirements for the Permittee to obtain additional permits or seek modification of this permit pursuant to 326 IAC 2, or change other applicable requirements presented in the permit application.

### A.1 General Information [326 IAC 2-7-4(c)][326 IAC 2-7-5(14)][326 IAC 2-7-1(22)]

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The Permittee owns and operates a stationary power plant and a combustion turbine plant.

Source Address:	3300 N SR 63, Cayuga, Indiana 47928
General Source Phone Number:	(317) 838-2108
SIC Code:	4911 (Electric Services)
County Location:	Vermillion
Source Location Status:	Attainment for all criteria pollutants
Source Status:	Part 70 Operating Permit Program Major Source, under PSD Rules Major Source, Section 112 of the Clean Air Act 1 of 28 Source Categories

### A.2 Part 70 Source Definition [326 IAC 2-7-1(22)]

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This source consists of a power plant and a combustion turbine plant:

- (a) Duke Energy Indiana, LLC - Cayuga Generating Station (ID # 165-00001), a power plant, is located at, SR 63, Cayuga, IN 47928; and
- (b) Duke Energy Indiana, LLC - Cayuga Generating Station Unit 4 combustion turbine plant (ID # 165-00086), is located at SR 63, Cayuga, IN 47928.

IDEM, OAQ has examined whether the Cayuga Generating Station plant and the combustion turbine plant are part of the same major source.

IDEM, OAQ finds that the two plants are part of the same major source. IDEM, OAQ will issue separate Part 70 permits to each plant solely for administrative purposes.

### A.3 Emission Units and Pollution Control Equipment Summary [326 IAC 2-7-4(c)(3)][326 IAC 2-7-5(14)]

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This stationary source consists of the following emission units and pollution control devices:

- (a) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 1, installed in 1967, using #2 fuel oil for startup, shutdown, and stabilization purposes, with a nominal heat input capacity of 4,802 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, a flue gas desulfurization (FGD) system for control of SO<sub>2</sub>, and exhausting to stack 1. Stack 1 has continuous emissions monitors (CEMs) for nitrogen oxides (NO<sub>x</sub>), sulfur dioxide (SO<sub>2</sub>), and particulate matter (PM). Boiler No. 1 was configured with a low NO<sub>x</sub> burner in 1993. Selective Catalytic Oxidation (SCR) to control NO<sub>x</sub>, and Dry Sorbent Injection System to Control SO<sub>3</sub> constructed in 2015. The Boiler is equipped with a PM CEMS, SO<sub>2</sub> CEMS, NO<sub>x</sub> CEMS and Hg CEMS.

[Under NESHAP Subpart UUUUU, this unit is part of an affected source.]



- (b) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 2, installed in 1968, using #2 fuel oil for startup, shutdown, and stabilization purposes, with a nominal heat input capacity of 4,802 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, a flue gas desulfurization (FGD) system for control of SO<sub>2</sub>, and exhausting to stack 2. Stack 2 has continuous emissions monitors (CEMs) for nitrogen oxides (NO<sub>x</sub>), sulfur dioxide (SO<sub>2</sub>), and particulate matter (PM). Boiler No. 2 was configured with a low NO<sub>x</sub> burner in 1993. Selective Catalytic Oxidation (SCR) to control NO<sub>x</sub>, and Dry Sorbent Injection System to Control SO<sub>3</sub> constructed in 2015. The Boiler is equipped with a PM CEMS, SO<sub>2</sub> CEMS, NO<sub>x</sub> CEMS and Hg CEMS.

[Under NESHAP Subpart UUUUU, this unit is part of an affected source.]

- (c) One (1) no. 2 fuel oil-fired generator, identified as Unit No. 3A, installed in 1972, with a nominal heat input capacity of 30 million Btu per hour (MMBtu/hr), using an oxidation catalyst installed in 2017 as control, and exhausting to stack 3A.

[This is an affected facility under 40 CFR 63, Subpart ZZZZ]

- (d) One (1) no. 2 fuel oil-fired generator, identified as Unit No. 3B, installed in 1972, with a nominal heat input capacity of 30 million Btu per hour (MMBtu/hr), using an oxidation catalyst installed in 2017 as control, and exhausting to stack 3B.

[This is an affected facility under 40 CFR 63, Subpart ZZZZ]

- (e) One (1) no. 2 fuel oil-fired generator, identified as Unit No. 3C, installed in 1972, with a nominal heat input capacity of 30 million Btu per hour (MMBtu/hr), using an oxidation catalyst installed in 2017 as control, and exhausting to stack 3C.

[This is an affected unit under 40 CFR 63, Subpart ZZZZ]

- (f) One (1) no. 2 fuel oil-fired generator, identified as Unit No. 3D, installed in, with a nominal heat input capacity of 30 million Btu per hour (MMBtu/hr), using an oxidation catalyst installed in 2017 as control, and exhausting to stack 3D.

[This is an affected unit under 40 CFR 63, Subpart ZZZZ]

- (g) A dual conveyor coal processing system, constructed in 1968, with a nominal throughput of 1900 tons of coal per hour (950 tons of coal per hour each side), consisting of the following equipment:

- (1) One (1) railcar unloading station with a drop point to two (2) hoppers, with a capacity of 1900 tons, identified as DP-1, with the drop point enclosed with emissions uncontrolled, and exhausting to the ambient air.
- (2) One (1) storage area having a nominal storage capacity including the active piles of 982,800 tons, with fugitive emissions controlled as needed by a watering truck.
- (3) One (1) enclosed hopper, with a drop point to a conveyor identified as DP-2, with a capacity of 1900 tons controlled by an enclosure and a water spray dust suppression system as needed and exhausting to the ambient air.
- (4) One (1) enclosed hopper and two (2) reclaim feeders, with a capacity of 1900 tons with an underground drop points identified as DP-10 and DP-12, with emissions controlled by the underground enclosure, and routed to the conveyor system.

- (5) An enclosed dual conveyor system, with six (6) drop points identified as DP-3 through DP-6, DP-8, and DP-13, with a capacity of 1900 tons controlled by enclosure and water spray dust suppression system as needed, exhausting to ambient air.
  - (6) An enclosed conveyor system with drop point identified as DP-9, with a capacity of 1900 tons controlled by a telescoping chute.
  - (7) Coal bunker, with one (1) drop point identified as DP-7, with a capacity of 1900 tons, controlled by a rotoclone.
- (h) One (1) limestone handling and storage system for the flue gas desulfurization system, constructed in 2006, with a maximum throughput rate of 1,000 tons per hour, consisting of the following:
- (1) One (1) railcar/truck unloading operation with a maximum capacity of 1,000 tons per hour, controlled by fog dust suppression, and exhausting to emission point EP-L1.
  - (2) Two (2) hoppers, each with a maximum capacity of 500 tons per hour controlled by fog dust suppression and exhausting to emission point EP-L2.
  - (3) Two (2) belt feeders, identified as LHBF-1 and LHBF-2 each with a maximum capacity of 500 tons per hour, controlled by fog dust suppression, and exhausting to emission point EP-L2.
  - (4) One (1) conveyor, identified as LH-1 controlled by a telescopic chute, and exhausting to emission point EP-L3. Under NSPS, Subpart OOO, this unit is considered a belt conveyor.
  - (5) One (1) active limestone stockout pile with a maximum capacity of 7,700 tons.
  - (6) One (1) inactive limestone storage pile with a maximum capacity of 45,000 tons.
  - (7) Two (2) reclaim hoppers each with a maximum capacity of 200 tons per hour, controlled by fog dust suppression, and exhausting to emission point EP-L4.
  - (8) Two (2) belt feeders, identified as LHBF-3 and LHBF-4 each with a maximum capacity of 200 tons per hour, controlled by fog dust suppression, and exhausting to emission point EP-L4.
  - (9) One (1) conveyor, identified as LH-2 with a maximum capacity of 400 tons per hour, controlled by fog dust suppression. The emissions exhaust out the general building vents, identified as emission point EP-L18a and EP-L18b. Under NSPS, Subpart OOO, this unit is considered a belt conveyor.
  - (10) One (1) reversible conveyor, identified as LH-3 with a maximum capacity of 400 tons per hour, controlled by fog dust suppression. The emissions exhaust out the general building vents, identified as emission points EP-L18a and EP-L18b. Under NSPS, Subpart OOO, this unit is considered a belt conveyor.
  - (11) Two (2) day bins each with a maximum throughput rate of 400 tons per hour. Each bin is equipped with a filter to control particulate emissions. Filters F-L1 and F-L2 exhaust to EP-L16 and EP-L17, respectively. Under NSPS, Subpart OOO, these units are considered storage bins.

- (12) Two (2) wet ball mills each with a maximum capacity of 51 tons of limestone slurry per hour. Under NSPS, Subpart OOO, these units are considered grinding mills.
- (i) One (1) gypsum handling and storage system, constructed in 2006, consisting of the following:
  - (1) One (1) wet gypsum conveying system with a maximum throughput rate of 150 tons per hour.
  - (2) Two (2) gypsum stock out piles Gypsum can be stocked out to an outside pile or a pile located in the gypsum stock out building. The maximum gypsum storage capacity is 10,400 tons.
  - (3) One (1) emergency gypsum stockout pile with a maximum capacity of 2,600 tons.
  - (4) One (1) dry gypsum transferring operation transferring gypsum to landfills by trucks on paved roads.
- (j) One (1) Auxiliary Boiler, identified as emission unit Aux, with a maximum heat input capacity of 72.76 MMBtu/hr fired with distillate oil and exhausting out one stack identified as stack Aux-1. The Auxiliary boiler was constructed before 1968.  
  
[Under NESHAP 40 CFR 63, Subpart DDDDD, this unit is part of an affected source]
- (k) One (1) Arsenic Mitigation System consisting of (1) 700 ton Limestone Storage Silo and (1) 300 ton Limestone Surge Bin, constructed in 2015. Limestone is pneumatically conveyed from delivery trucks to the Limestone Storage Silo and from the Limestone Storage Silo to the Limestone Surge Bin. Limestone in the Surge Bin is dropped on to the C-1 and C-2 coal conveyors. PM emissions generated during pneumatic conveying and transfer points to the C-1 and C-2 conveyor will be controlled by the bin vent filters. The Limestone Storage Silo and Limestone Surge Bin are identified as emissions points EP-01(LS) and EP-02(LS).
- (l) Two (2) Dry Sorbent Injection (DSI) Systems, one for each Unit. Each DSI system consists of one (1) Sorbent Storage Silo with a storage capacity of 120 tons, three (3) Silo Weight Feeders to regulate sorbent from the silos and a system to inject the sorbent material into the flue gas, constructed 2015. PM emissions generated during loading operations are controlled by a Bin Vent Filter located on the top of each silo and the weight feeders. The two (2) Sorbent Silos are identified as emission points EP-01(DSI), and EP-03(DSI). The weight feeders are identified as EP-05A(DSI), EP-05B(DSI), EP-06A(DSI) and EP-06B(DSI) with spares EP-05C(DSI) and EP-06C(DSI).
- (m) Two (2) Dry Ash Handling Systems, one for each Unit. The dry ash handling system consists of a pneumatic conveying system, five (5) baghouse separators, one (1) ash silo with a storage capacity of 3,500 and an ash unloading system, constructed in 2015.
  - (i) Baghouse Separators - Fly ash from the ESP Ash Hoppers, Air Heater Ash Hoppers, Economizer Ash Hoppers and SCR Large Particle Screen. Ash Hopper will be pneumatically conveyed to one of five (5) baghouse separators. There will be two (2) baghouse separators for each unit. The dry fly ash is separated from the air stream in a baghouse separator. Each baghouse separator is identified as emissions points EP-01(DFA), EP-02(DFA), EP-03(DFA), and EP-04(DFA). The system is equipped with a spare exhauster identified as emissions point EP-

05(DFA).

- (ii) Ash Silos - Fly ash collected in the baghouse separators is dropped into a feeder and pneumatically conveyed to the ash silo. The ash silo is equipped with a bin vent filter to control particulate matter emissions from pneumatic conveying. The Ash Silo is identified as emission point EP-06(DFA).
- (iii) Ash Unloading Operation - Fly ash collected in the silos can be unloaded into trucks or pneumatically conveyed to the ash fixation process. Fly ash unloaded into trucks can be unloaded dry or wet. Fly ash unloaded dry is gravity feed to a chute and unloaded into enclosed trucks for beneficial reuse offsite. The emissions generated from unloading the ash dry are vented back to the silo and controlled by the silo bin vent filter. Ash unloaded wet is fed into a pin mixer where the ash is mixed with water and unloaded into open trucks for disposal in the onsite landfill.
- (n) One (1) Ash Fixation Process consisting of a pneumatic conveying system, one (1) lime silo, conveyors, and two (2) pin mixers.
  - (i) Lime Silo – Lime will be delivered by truck and will be pneumatically loaded into the silo. The storage capacity of the silo is 300 tons, constructed in 2015. The emissions generated by the pneumatic conveying will be controlled by a bin vent filter located on top of the lime silo. The Lime Silo is identified as emissions point EP-02(FIX).
  - (ii) Conveyor and Transfer Points – Fly ash, Lime and Gypsum will be conveyed to one of two (2) pin mixers where this material will be mixed with water to make the fixated ash constructed in 2015. The fixated ash will be unloaded to a storage pile, loaded into trucks using front end loaders and hauled to the landfill.

A.4 Specifically Regulated Insignificant Activities  
[326 IAC 2-7-1(21)][326 IAC 2-7-4(c)][326 IAC 2-7-5(14)]

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This stationary source also includes the following insignificant activities which are specifically regulated, as defined in 326 IAC 2-7-1(21):

- (a) Degreasing operations that do not exceed one hundred forty-five (145) gallons per twelve months, except if subject to 326 IAC 20-6. [326 IAC 8-3-2] [326 IAC 8-3-8]
- (b) One (1) Diesel Fired Emergency Generator, identified as ENG-01 with maximum capacity of 156.9 HP (100 kW), CI ICE with a displacement 4.4 liters, Manufactured by Caterpillar Model Year 2007, Model D100-6, constructed in 2007, exhausting outside the building. This generator is located in the switch yard and is operated as backup for the black start diesel aux feed.  
  
[This is an affected facility under 40 CFR 60, Subpart IIII]  
[This is an affected unit under 40 CFR 63, Subpart ZZZZ]
- (c) One (1) Diesel Fired Emergency Engine, identified as ENG-02, with maximum capacity of 713 Hp (450 kW), CI ICE with a displacement 15.2 liters, Manufactured by Caterpillar, Model Year 2007, Model C15DITA, constructed in 2007, exhausting outside the building. This engine is used to quench the flue gas if the scrubber should fail.  
  
[This is an affected facility under 40 CFR 60, Subpart IIII]  
[This is an affected unit under 40 CFR 63, Subpart ZZZZ]
- (d) One (1) Emergency Fire Pump Engine, identified as ENG-03, with maximum capacity of

430 Hp (321 kW) CI, manufactured by Caterpillar, Model Year 2005, Model 3406, exhausting outside the building.

[This is an affected unit under 40 CFR 63, Subpart ZZZZ]

- (e) One (1) SI emergency engine, identified as ENG-04 with maximum capacity of 67 Hp (50 kW), manufactured by Power Solutions International, fired with LPG, model year 2018 exhausting outside the building. The engine is used provide backup power to a microwave tower during the loss of power.

[This is an affected facility under 40 CFR 60, Subpart JJJJ]

[This is an affected unit under 40 CFR 63, Subpart ZZZZ]

- (f) One (1) SI propane emergency generator, identified as ENG-05, permitted in 2024, with a maximum capacity of 229 brake horsepower, using no controls, and exhausting to atmosphere.

[This is an affected facility under 40 CFR 60, Subpart JJJJ]

[This is an affected unit under 40 CFR 63, Subpart ZZZZ]

#### A.5 Part 70 Permit Applicability [326 IAC 2-7-2]

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This stationary source is required to have a Part 70 permit by 326 IAC 2-7-2 (Applicability) because:

- (a) It is a major source, as defined in 326 IAC 2-7-1(22);
- (b) It is a source in a source category designated by the United States Environmental Protection Agency (U.S. EPA) under 40 CFR 70.3 (Part 70 - Applicability).
- (c) It is an affected source under Title IV (Acid Deposition Control) of the Clean Air Act, as defined in 326 IAC 2-7-1(3);

## **SECTION B GENERAL CONDITIONS**

### **B.1 Definitions [326 IAC 2-7-1]**

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Terms in this permit shall have the definition assigned to such terms in the referenced regulation. In the absence of definitions in the referenced regulation, the applicable definitions found in the statutes or regulations (IC 13-11, 326 IAC 1-2 and 326 IAC 2-7) shall prevail.

### **B.2 Permit Term [326 IAC 2-7-5(2)][326 IAC 2-1.1-9.5][326 IAC 2-7-4(a)(1)(D)][IC 13-15-3-6(a)]**

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- (a) This permit, T165-47094-00001, is issued for a fixed term of five (5) years from the issuance date of this permit, as determined in accordance with IC 4-21.5-3-5(f) and IC 13-15-5-3. Subsequent revisions, modifications, or amendments of this permit do not affect the expiration date of this permit or of permits issued pursuant to Title IV of the Clean Air Act and 326 IAC 21 (Acid Deposition Control).
- (b) If IDEM, OAQ, upon receiving a timely and complete renewal permit application, fails to issue or deny the permit renewal prior to the expiration date of this permit, this existing permit shall not expire and all terms and conditions shall continue in effect, including any permit shield provided in 326 IAC 2-7-15, until the renewal permit has been issued or denied.

### **B.3 Term of Conditions [326 IAC 2-1.1-9.5]**

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Notwithstanding the permit term of a permit to construct, a permit to operate, or a permit modification, any condition established in a permit issued pursuant to a permitting program approved in the state implementation plan shall remain in effect until:

- (a) the condition is modified in a subsequent permit action pursuant to Title I of the Clean Air Act; or
- (b) the emission unit to which the condition pertains permanently ceases operation.

### **B.4 Enforceability [326 IAC 2-7-7] [IC 13-17-12]**

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Unless otherwise stated, all terms and conditions in this permit, including any provisions designed to limit the source's potential to emit, are enforceable by IDEM, the United States Environmental Protection Agency (U.S. EPA) and by citizens in accordance with the Clean Air Act.

### **B.5 Severability [326 IAC 2-7-5(5)]**

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The provisions of this permit are severable; a determination that any portion of this permit is invalid shall not affect the validity of the remainder of the permit.

### **B.6 Property Rights or Exclusive Privilege [326 IAC 2-7-5(6)(D)]**

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This permit does not convey any property rights of any sort or any exclusive privilege.

### **B.7 Duty to Provide Information [326 IAC 2-7-5(6)(E)]**

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- (a) The Permittee shall furnish to IDEM, OAQ, within a reasonable time, any information that IDEM, OAQ may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with this permit. Upon request, the Permittee shall also furnish to IDEM, OAQ copies of records required to be kept by this permit.
- (b) For information furnished by the Permittee to IDEM, OAQ, the Permittee may include a claim of confidentiality in accordance with 326 IAC 17.1. When furnishing copies of requested records directly to U. S. EPA, the Permittee may assert a claim of confidentiality in accordance with 40 CFR 2, Subpart B.

B.8 Certification [326 IAC 2-7-4(f)][326 IAC 2-7-6(1)][326 IAC 2-7-5(3)(C)]

- (a) A certification required by this permit meets the requirements of 326 IAC 2-7-6(1) if:
- (1) it contains a certification by a "responsible official" as defined by 326 IAC 2-7-1(35), and
  - (2) the certification states that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.
- (b) The Permittee may use the attached Certification Form, or its equivalent with each submittal requiring certification. One (1) certification may cover multiple forms in one (1) submittal.
- (c) A "responsible official" is defined at 326 IAC 2-7-1(35).

B.9 Annual Compliance Certification [326 IAC 2-7-6(5)]

- (a) The Permittee shall annually submit a compliance certification report which addresses the status of the source's compliance with the terms and conditions contained in this permit, including emission limitations, standards, or work practices. All certifications shall cover the time period from January 1 to December 31 of the previous year, and shall be submitted no later than July 1 of each year to:

Indiana Department of Environmental Management  
Compliance and Enforcement Branch, Office of Air Quality  
100 North Senate Avenue  
MC 61-53 IGCN 1003  
Indianapolis, Indiana 46204-2251

and

United States Environmental Protection Agency, Region 5  
Air and Radiation Division, Air Enforcement Branch - Indiana (AE-17J)  
77 West Jackson Boulevard  
Chicago, Illinois 60604-3590

- (b) The annual compliance certification report required by this permit shall be considered timely if the date postmarked on the envelope or certified mail receipt, or affixed by the shipper on the private shipping receipt, is on or before the date it is due. If the document is submitted by any other means, it shall be considered timely if received by IDEM, OAQ on or before the date it is due.
- (c) The annual compliance certification report shall include the following:
- (1) The appropriate identification of each term or condition of this permit that is the basis of the certification;
  - (2) The compliance status;
  - (3) Whether compliance was continuous or intermittent;
  - (4) The methods used for determining the compliance status of the source, currently and over the reporting period consistent with 326 IAC 2-7-5(3); and
  - (5) Such other facts, as specified in Sections D of this permit, as IDEM, OAQ may require to determine the compliance status of the source.

The submittal by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

B.10 Preventive Maintenance Plan [326 IAC 2-7-5(12)][326 IAC 1-6-3]

- (a) A Preventive Maintenance Plan meets the requirements of 326 IAC 1-6-3 if it includes, at a minimum:
- (1) Identification of the individual(s) responsible for inspecting, maintaining, and repairing emission control devices;
  - (2) A description of the items or conditions that will be inspected and the inspection schedule for said items or conditions; and
  - (3) Identification and quantification of the replacement parts that will be maintained in inventory for quick replacement.

The Permittee shall implement the PMPs.

- (b) If required by specific condition(s) in Section D of this permit where no PMP was previously required, the Permittee shall prepare and maintain Preventive Maintenance Plans (PMPs) no later than ninety (90) days after issuance of this permit or ninety (90) days after initial start-up, whichever is later, including the following information on each facility:
- (1) Identification of the individual(s) responsible for inspecting, maintaining, and repairing emission control devices;
  - (2) A description of the items or conditions that will be inspected and the inspection schedule for said items or conditions; and
  - (3) Identification and quantification of the replacement parts that will be maintained in inventory for quick replacement.

If, due to circumstances beyond the Permittee's control, the PMPs cannot be prepared and maintained within the above time frame, the Permittee may extend the date an additional ninety (90) days provided the Permittee notifies:

Indiana Department of Environmental Management  
Compliance and Enforcement Branch, Office of Air Quality  
100 North Senate Avenue  
MC 61-53 IGCN 1003  
Indianapolis, Indiana 46204-2251

The PMP extension notification does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

The Permittee shall implement the PMPs.

- (c) A copy of the PMPs shall be submitted to IDEM, OAQ upon request and within a reasonable time, and shall be subject to review and approval by IDEM, OAQ. IDEM, OAQ may require the Permittee to revise its PMPs whenever lack of proper maintenance causes or is the primary contributor to an exceedance of any limitation on emissions. The PMPs and their submittal do not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).



- (d) To the extent the Permittee is required by 40 CFR Part 60/63 to have an Operation Maintenance, and Monitoring (OMM) Plan for a unit, such Plan is deemed to satisfy the PMP requirements of 326 IAC 1-6-3 for that unit.

B.11 Emergency Provisions [326 IAC 2-7-16]

- (a) An emergency, as defined in 326 IAC 2-7-1(12), is not an affirmative defense for an action brought for noncompliance with a federal or state health-based emission limitation.

- (b) An emergency, as defined in 326 IAC 2-7-1(12), constitutes an affirmative defense to an action brought for noncompliance with a technology-based emission limitation if the affirmative defense of an emergency is demonstrated through properly signed, contemporaneous operating logs or other relevant evidence that describe the following:

- (1) An emergency occurred and the Permittee can, to the extent possible, identify the causes of the emergency;
- (2) The permitted facility was at the time being properly operated;
- (3) During the period of an emergency, the Permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards or other requirements in this permit;
- (4) For each emergency lasting one (1) hour or more, the Permittee notified IDEM, OAQ within four (4) daytime business hours after the beginning of the emergency, or after the emergency was discovered or reasonably should have been discovered;

Telephone Number: 1-800-451-6027 (ask for Office of Air Quality, Compliance and Enforcement Branch), or  
Telephone Number: 317-233-0178 (ask for Office of Air Quality, Compliance and Enforcement Branch)  
Facsimile Number: 317-233-6865

- (5) For each emergency lasting one (1) hour or more, the Permittee submitted the attached Emergency Occurrence Report Form or its equivalent, either by mail or facsimile to:

Indiana Department of Environmental Management  
Compliance and Enforcement Branch, Office of Air Quality  
100 North Senate Avenue  
MC 61-53 IGCN 1003  
Indianapolis, Indiana 46204-2251

within two (2) working days of the time when emission limitations were exceeded due to the emergency.

The notice fulfills the requirement of 326 IAC 2-7-5(3)(C)(ii) and must contain the following:

- (A) A description of the emergency;
- (B) Any steps taken to mitigate the emissions; and
- (C) Corrective actions taken.

The notification which shall be submitted by the Permittee does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

- (6) The Permittee immediately took all reasonable steps to correct the emergency.
- (c) In any enforcement proceeding, the Permittee seeking to establish the occurrence of an emergency has the burden of proof.
- (d) This emergency provision supersedes 326 IAC 1-6 (Malfunctions). This permit condition is in addition to any emergency or upset provision contained in any applicable requirement.
- (e) The Permittee seeking to establish the occurrence of an emergency shall make records available upon request to ensure that failure to implement a PMP did not cause or contribute to an exceedance of any limitations on emissions. However, IDEM, OAQ may require that the Preventive Maintenance Plans required under 326 IAC 2-7-4(c)(8) be revised in response to an emergency.
- (f) Failure to notify IDEM, OAQ by telephone or facsimile of an emergency lasting more than one (1) hour in accordance with (b)(4) and (5) of this condition shall constitute a violation of 326 IAC 2-7 and any other applicable rules.
- (g) If the emergency situation causes a deviation from a technology-based limit, the Permittee may continue to operate the affected emitting facilities during the emergency provided the Permittee immediately takes all reasonable steps to correct the emergency and minimize emissions.

B.12 Permit Shield [326 IAC 2-7-15][326 IAC 2-7-20][326 IAC 2-7-12]

- (a) Pursuant to 326 IAC 2-7-15, the Permittee has been granted a permit shield. The permit shield provides that compliance with the conditions of this permit shall be deemed compliance with any applicable requirements as of the date of permit issuance, provided that either the applicable requirements are included and specifically identified in this permit or the permit contains an explicit determination or concise summary of a determination that other specifically identified requirements are not applicable. The Indiana statutes from IC 13 and rules from 326 IAC, referenced in conditions in this permit, are those applicable at the time the permit was issued. The issuance or possession of this permit shall not alone constitute a defense against an alleged violation of any law, regulation or standard, except for the requirement to obtain a Part 70 permit under 326 IAC 2-7 or for applicable requirements for which a permit shield has been granted.

This permit shield does not extend to applicable requirements which are promulgated after the date of issuance of this permit unless this permit has been modified to reflect such new requirements.

- (b) If, after issuance of this permit, it is determined that the permit is in nonconformance with an applicable requirement that applied to the source on the date of permit issuance, IDEM, OAQ shall immediately take steps to reopen and revise this permit and issue a compliance order to the Permittee to ensure expeditious compliance with the applicable requirement until the permit is reissued. The permit shield shall continue in effect so long as the Permittee is in compliance with the compliance order.
- (c) No permit shield shall apply to any permit term or condition that is determined after issuance of this permit to have been based on erroneous information supplied in the permit application. Erroneous information means information that the Permittee knew to

be false, or in the exercise of reasonable care should have been known to be false, at the time the information was submitted.

- (d) Nothing in 326 IAC 2-7-15 or in this permit shall alter or affect the following:
- (1) The provisions of Section 303 of the Clean Air Act (emergency orders), including the authority of the U.S. EPA under Section 303 of the Clean Air Act;
  - (2) The liability of the Permittee for any violation of applicable requirements prior to or at the time of this permit's issuance;
  - (3) The applicable requirements of the acid rain program, consistent with Section 408(a) of the Clean Air Act; and
  - (4) The ability of U.S. EPA to obtain information from the Permittee under Section 114 of the Clean Air Act.
- (e) This permit shield is not applicable to any change made under 326 IAC 2-7-20(b)(2) (Sections 502(b)(10) of the Clean Air Act changes) and 326 IAC 2-7-20(c)(2) (trading based on State Implementation Plan (SIP) provisions).
- (f) This permit shield is not applicable to modifications eligible for group processing until after IDEM, OAQ, has issued the modifications. [326 IAC 2-7-12(c)(7)]
- (g) This permit shield is not applicable to minor Part 70 permit modifications until after IDEM, OAQ, has issued the modification. [326 IAC 2-7-12(b)(8)]

**B.13 Prior Permits Superseded [326 IAC 2-1.1-9.5][326 IAC 2-7-10.5]**

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- (a) All terms and conditions of permits established prior to T165-47094-00001 and issued pursuant to permitting programs approved into the state implementation plan have been either:
- (1) incorporated as originally stated,
  - (2) revised under 326 IAC 2-7-10.5, or
  - (3) deleted under 326 IAC 2-7-10.5.
- (b) Provided that all terms and conditions are accurately reflected in this permit, all previous registrations and permits are superseded by this Part 70 operating permit, except for permits issued pursuant to Title IV of the Clean Air Act and 326 IAC 21 (Acid Deposition Control)

**B.14 Termination of Right to Operate [326 IAC 2-7-10][326 IAC 2-7-4(a)]**

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The Permittee's right to operate this source terminates with the expiration of this permit unless a timely and complete renewal application is submitted at least nine (9) months prior to the date of expiration of the source's existing permit, consistent with 326 IAC 2-7-3 and 326 IAC 2-7-4(a).

**B.15 Permit Modification, Reopening, Revocation and Reissuance, or Termination [326 IAC 2-7-5(6)(C)][326 IAC 2-7-8(a)][326 IAC 2-7-9]**

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- (a) This permit may be modified, reopened, revoked and reissued, or terminated for cause. The filing of a request by the Permittee for a Part 70 Operating Permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any condition of this permit. [326 IAC 2-7-5(6)(C)] The notification by the Permittee does require a certification that

meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

- (b) This permit shall be reopened and revised under any of the circumstances listed in IC 13-15-7-2 or if IDEM, OAQ determines any of the following:
  - (1) That this permit contains a material mistake.
  - (2) That inaccurate statements were made in establishing the emissions standards or other terms or conditions.
  - (3) That this permit must be revised or revoked to assure compliance with an applicable requirement. [326 IAC 2-7-9(a)(3)]
- (c) Proceedings by IDEM, OAQ to reopen and revise this permit shall follow the same procedures as apply to initial permit issuance and shall affect only those parts of this permit for which cause to reopen exists. Such reopening and revision shall be made as expeditiously as practicable. [326 IAC 2-7-9(b)]
- (d) The reopening and revision of this permit, under 326 IAC 2-7-9(a), shall not be initiated before notice of such intent is provided to the Permittee by IDEM, OAQ at least thirty (30) days in advance of the date this permit is to be reopened, except that IDEM, OAQ may provide a shorter time period in the case of an emergency. [326 IAC 2-7-9(c)]

B.16 Permit Renewal [326 IAC 2-7-3][326 IAC 2-7-4][326 IAC 2-7-8(e)]

- (a) The application for renewal shall be submitted using the application form or forms prescribed by IDEM, OAQ and shall include the information specified in 326 IAC 2-7-4. Such information shall be included in the application for each emission unit at this source, except those emission units included on the trivial or insignificant activities list contained in 326 IAC 2-7-1(21) and 326 IAC 2-7-1(42). The renewal application does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

Request for renewal shall be submitted to:

Indiana Department of Environmental Management  
Permit Administration and Support Section, Office of Air Quality  
100 North Senate Avenue  
MC 61-53 IGCN 1003  
Indianapolis, Indiana 46204-2251

- (b) A timely renewal application is one that is:
  - (1) Submitted at least nine (9) months prior to the date of the expiration of this permit; and
  - (2) If the date postmarked on the envelope or certified mail receipt, or affixed by the shipper on the private shipping receipt, is on or before the date it is due. If the document is submitted by any other means, it shall be considered timely if received by IDEM, OAQ on or before the date it is due.
- (c) If the Permittee submits a timely and complete application for renewal of this permit, the source's failure to have a permit is not a violation of 326 IAC 2-7 until IDEM, OAQ takes final action on the renewal application, except that this protection shall cease to apply if, subsequent to the completeness determination, the Permittee fails to submit by the

deadline specified, pursuant to 326 IAC 2-7-4(a)(2)(D), in writing by IDEM, OAQ any additional information identified as being needed to process the application.

**B.17 Permit Amendment or Modification [326 IAC 2-7-11][326 IAC 2-7-12] [40 CFR 72]**

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- (a) Permit amendments and modifications are governed by the requirements of 326 IAC 2-7-11 or 326 IAC 2-7-12 whenever the Permittee seeks to amend or modify this permit.
- (b) Pursuant to 326 IAC 2-7-11(b) and 326 IAC 2-7-12(a), administrative Part 70 operating permit amendments and permit modifications for purposes of the acid rain portion of a Part 70 permit shall be governed by regulations promulgated under Title IV of the Clean Air Act. [40 CFR 72]
- (c) Any application requesting an amendment or modification of this permit shall be submitted to:  
  
Indiana Department of Environmental Management  
Permit Administration and Support Section, Office of Air Quality  
100 North Senate Avenue  
MC 61-53 IGCN 1003  
Indianapolis, Indiana 46204-2251  
  
Any such application does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).
- (d) The Permittee may implement administrative amendment changes addressed in the request for an administrative amendment immediately upon submittal of the request. [326 IAC 2-7-11(c)(3)]

**B.18 Permit Revision Under Economic Incentives and Other Programs  
[326 IAC 2-7-5(8)][326 IAC 2-7-12(b)(2)]**

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- (a) No Part 70 permit revision or notice shall be required under any approved economic incentives, marketable Part 70 permits, emissions trading, and other similar programs or processes for changes that are provided for in a Part 70 permit.
- (b) Notwithstanding 326 IAC 2-7-12(b)(1) and 326 IAC 2-7-12(c)(1), minor Part 70 permit modification procedures may be used for Part 70 modifications involving the use of economic incentives, marketable Part 70 permits, emissions trading, and other similar approaches to the extent that such minor Part 70 permit modification procedures are explicitly provided for in the applicable State Implementation Plan (SIP) or in applicable requirements promulgated or approved by the U.S. EPA.

**B.19 Operational Flexibility [326 IAC 2-7-20][326 IAC 2-7-10.5]**

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- (a) The Permittee may make any change or changes at the source that are described in 326 IAC 2-7-20(b) or (c) without a prior permit revision, if each of the following conditions is met:
  - (1) The changes are not modifications under any provision of Title I of the Clean Air Act;
  - (2) Any preconstruction approval required by 326 IAC 2-7-10.5 has been obtained;
  - (3) The changes do not result in emissions which exceed the limitations provided in this permit (whether expressed herein as a rate of emissions or in terms of total emissions);

- (4) The Permittee notifies the:

Indiana Department of Environmental Management  
Permit Administration and Support Section, Office of Air Quality  
100 North Senate Avenue  
MC 61-53 IGCN 1003  
Indianapolis, Indiana 46204-2251

and

United States Environmental Protection Agency, Region 5  
Air and Radiation Division, Regulation Development Branch - Indiana (AR-18J)  
77 West Jackson Boulevard  
Chicago, Illinois 60604-3590

in advance of the change by written notification at least ten (10) days in advance of the proposed change. The Permittee shall attach every such notice to the Permittee's copy of this permit; and

- (5) The Permittee maintains records on-site, on a rolling five (5) year basis, which document all such changes and emission trades that are subject to 326 IAC 2-7-20(b)(1) and (c)(1). The Permittee shall make such records available, upon reasonable request, for public review.

Such records shall consist of all information required to be submitted to IDEM, OAQ in the notices specified in 326 IAC 2-7-20(b)(1) and (c)(1).

- (b) The Permittee may make Section 502(b)(10) of the Clean Air Act changes (this term is defined at 326 IAC 2-7-1(37)) without a permit revision, subject to the constraint of 326 IAC 2-7-20(a). For each such Section 502(b)(10) of the Clean Air Act change, the required written notification shall include the following:

- (1) A brief description of the change within the source;
- (2) The date on which the change will occur;
- (3) Any change in emissions; and
- (4) Any permit term or condition that is no longer applicable as a result of the change.

The notification which shall be submitted is not considered an application form, report or compliance certification. Therefore, the notification by the Permittee does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

- (c) Emission Trades [326 IAC 2-7-20(c)]  
The Permittee may trade emissions increases and decreases at the source, where the applicable SIP provides for such emission trades without requiring a permit revision, subject to the constraints of Section (a) of this condition and those in 326 IAC 2-7-20(c).
- (d) Alternative Operating Scenarios [326 IAC 2-7-20(d)]  
The Permittee may make changes at the source within the range of alternative operating scenarios that are described in the terms and conditions of this permit in accordance with 326 IAC 2-7-5(9). No prior notification of IDEM, OAQ or U.S. EPA is required.

- (e) Backup fuel switches specifically addressed in, and limited under, Section D of this permit shall not be considered alternative operating scenarios. Therefore, the notification requirements of part (a) of this condition do not apply.
- (f) This condition does not apply to emission trades of SO<sub>2</sub> or NO<sub>x</sub> under 326 IAC 21.

**B.20 Source Modification Requirement [326 IAC 2-7-10.5]**

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A modification, construction, or reconstruction is governed by the requirements of 326 IAC 2.

**B.21 Inspection and Entry [326 IAC 2-7-6][IC 13-14-2-2][IC 13-30-3-1][IC 13-17-3-2]**

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Upon presentation of proper identification cards, credentials, and other documents as may be required by law, and subject to the Permittee's right under all applicable laws and regulations to assert that the information collected by the agency is confidential and entitled to be treated as such, the Permittee shall allow IDEM, OAQ, U.S. EPA, or an authorized representative to perform the following:

- (a) Enter upon the Permittee's premises where a Part 70 source is located, or emissions related activity is conducted, or where records must be kept under the conditions of this permit;
- (b) As authorized by the Clean Air Act, IC 13-14-2-2, IC 13-17-3-2, and IC 13-30-3-1, have access to and copy any records that must be kept under the conditions of this permit;
- (c) As authorized by the Clean Air Act, IC 13-14-2-2, IC 13-17-3-2, and IC 13-30-3-1, inspect any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit;
- (d) As authorized by the Clean Air Act, IC 13-14-2-2, IC 13-17-3-2, and IC 13-30-3-1, sample or monitor substances or parameters for the purpose of assuring compliance with this permit or applicable requirements; and
- (e) As authorized by the Clean Air Act, IC 13-14-2-2, IC 13-17-3-2, and IC 13-30-3-1, utilize any photographic, recording, testing, monitoring, or other equipment for the purpose of assuring compliance with this permit or applicable requirements.

**B.22 Transfer of Ownership or Operational Control [326 IAC 2-7-11]**

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- (a) The Permittee must comply with the requirements of 326 IAC 2-7-11 whenever the Permittee seeks to change the ownership or operational control of the source and no other change in the permit is necessary.
- (b) Any application requesting a change in the ownership or operational control of the source shall contain a written agreement containing a specific date for transfer of permit responsibility, coverage and liability between the current and new Permittee. The application shall be submitted to:

Indiana Department of Environmental Management  
Permit Administration and Support Section, Office of Air Quality  
100 North Senate Avenue  
MC 61-53 IGCN 1003  
Indianapolis, Indiana 46204-2251

Any such application does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

- (c) The Permittee may implement administrative amendment changes addressed in the request for an administrative amendment immediately upon submittal of the request. [326 IAC 2-7-11(c)(3)]

B.23 Annual Fee Payment [326 IAC 2-7-19] [326 IAC 2-7-5(7)][326 IAC 2-1.1-7]

- (a) The Permittee shall pay annual fees to IDEM, OAQ within thirty (30) calendar days of receipt of a billing. Pursuant to 326 IAC 2-7-19(b), if the Permittee does not receive a bill from IDEM, OAQ the applicable fee is due April 1 of each year.
- (b) Except as provided in 326 IAC 2-7-19(e), failure to pay may result in administrative enforcement action or revocation of this permit.
- (c) The Permittee may call the following telephone numbers: 1-800-451-6027 or 317-233-8590 (ask for OAQ, Billing, Licensing, and Training Section), to determine the appropriate permit fee.

B.24 Credible Evidence [326 IAC 2-7-5(3)][326 IAC 2-7-6][62 FR 8314] [326 IAC 1-1-6]

For the purpose of submitting compliance certifications or establishing whether or not the Permittee has violated or is in violation of any condition of this permit, nothing in this permit shall preclude the use, including the exclusive use, of any credible evidence or information relevant to whether the Permittee would have been in compliance with the condition of this permit if the appropriate performance or compliance test or procedure had been performed.



## SECTION C

## SOURCE OPERATION CONDITIONS

Entire Source

### Emission Limitations and Standards [326 IAC 2-7-5(1)]

**C.1 Particulate Emission Limitations For Processes with Process Weight Rates Less Than One Hundred (100) Pounds per Hour [326 IAC 6-3-2]**

Pursuant to 326 IAC 6-3-2(e)(2), particulate emissions from any process not exempt under 326 IAC 6-3-1(b) or (c) which has a maximum process weight rate less than 100 pounds per hour and the methods in 326 IAC 6-3-2(b) through (d) do not apply shall not exceed 0.551 pounds per hour.

**C.2 Opacity [326 IAC 5-1]**

Pursuant to 326 IAC 5-1-2 (Opacity Limitations), except as provided in 326 IAC 5-1-1 (Applicability) and 326 IAC 5-1-3 (Temporary Alternative Opacity Limitations), opacity shall meet the following, unless otherwise stated in this permit:

- (a) Opacity shall not exceed an average of forty percent (40%) in any one (1) six (6) minute averaging period as determined in 326 IAC 5-1-4.
- (b) Opacity shall not exceed sixty percent (60%) for more than a cumulative total of fifteen (15) minutes (sixty (60) readings as measured according to 40 CFR 60, Appendix A, Method 9 or fifteen (15) one (1) minute nonoverlapping integrated averages for a continuous opacity monitor) in a six (6) hour period.

**C.3 Open Burning [326 IAC 4-1] [IC 13-17-9]**

The Permittee shall not open burn any material except as provided in 326 IAC 4-1-3, 326 IAC 4-1-4 or 326 IAC 4-1-6. The previous sentence notwithstanding, the Permittee may open burn in accordance with an open burning approval issued by the Commissioner under 326 IAC 4-1-4.1.

**C.4 Incineration [326 IAC 4-2] [326 IAC 9-1-2]**

The Permittee shall not operate an incinerator except as provided in 326 IAC 4-2 or in this permit. The Permittee shall not operate a refuse incinerator or refuse burning equipment except as provided in 326 IAC 9-1-2 or in this permit.

**C.5 Fugitive Dust Emissions [326 IAC 6-4]**

The Permittee shall not allow fugitive dust to escape beyond the property line or boundaries of the property, right-of-way, or easement on which the source is located, in a manner that would violate 326 IAC 6-4 (Fugitive Dust Emissions). 326 IAC 6-4-2(4) is not federally enforceable.

**C.6 Stack Height [326 IAC 1-7]**

The Permittee shall comply with the applicable provisions of 326 IAC 1-7 (Stack Height Provisions), for all exhaust stacks through which a potential (before controls) of twenty-five (25) tons per year or more of particulate matter or sulfur dioxide is emitted. The provisions of 326 IAC 1-7-1(3), 326 IAC 1-7-2, 326 IAC 1-7-3(c) and (d), 326 IAC 1-7-4, and 326 IAC 1-7-5(a), (b), and (d) are not federally enforceable.

**C.7 Asbestos Abatement Projects [326 IAC 14-10] [326 IAC 18] [40 CFR 61, Subpart M]**

- (a) Notification requirements apply to each owner or operator. If the combined amount of regulated asbestos containing material (RACM) to be stripped, removed or disturbed is at least 260 linear feet on pipes or 160 square feet on other facility components, or at least thirty-five (35) cubic feet on all facility components, then the notification requirements of

326 IAC 14-10-3 are mandatory. All demolition projects require notification whether or not asbestos is present.

- (b) The Permittee shall ensure that a written notification is sent on a form provided by the Commissioner at least ten (10) working days before asbestos stripping or removal work or before demolition begins, per 326 IAC 14-10-3, and shall update such notice as necessary, including, but not limited to the following:
  - (1) When the amount of affected asbestos containing material increases or decreases by at least twenty percent (20%); or
  - (2) If there is a change in the following:
    - (A) Asbestos removal or demolition start date;
    - (B) Removal or demolition contractor; or
    - (C) Waste disposal site.
- (c) The Permittee shall ensure that the notice is postmarked or delivered according to the guidelines set forth in 326 IAC 14-10-3(c).
- (d) The notice to be submitted shall include the information enumerated in 326 IAC 14-10-3(d).

All required notifications shall be submitted to:

Indiana Department of Environmental Management  
Compliance and Enforcement Branch, Office of Air Quality  
100 North Senate Avenue  
MC 61-53 IGCN 1003  
Indianapolis, Indiana 46204-2251

The notice shall include a signed certification from the owner or operator that the information provided in this notification is correct and that only Indiana licensed workers and project supervisors will be used to implement the asbestos removal project. The notifications do not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

- (e) **Procedures for Asbestos Emission Control**  
The Permittee shall comply with the applicable emission control procedures in 326 IAC 14-10-4 and 40 CFR 61.145(c). Per 326 IAC 14-10-1, emission control requirements are applicable for any removal or disturbance of RACM greater than three (3) linear feet on pipes or three (3) square feet on any other facility components or a total of at least 0.75 cubic feet on all facility components.
- (f) **Demolition and Renovation**  
The Permittee shall thoroughly inspect the affected facility or part of the facility where the demolition or renovation will occur for the presence of asbestos pursuant to 40 CFR 61.145(a).
- (g) **Indiana Licensed Asbestos Inspector**  
The Permittee shall comply with 326 IAC 14-10-1(a) that requires the owner or operator, prior to a renovation/demolition, to use an Indiana Licensed Asbestos Inspector to thoroughly inspect the affected portion of the facility for the presence of asbestos. The requirement to use an Indiana Licensed Asbestos inspector is not federally enforceable.

### **Testing Requirements [326 IAC 2-7-6(1)]**

#### **C.8 Performance Testing [326 IAC 3-6]**

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- (a) For performance testing required by this permit, a test protocol, except as provided elsewhere in this permit, shall be submitted to:

Indiana Department of Environmental Management  
Compliance and Enforcement Branch, Office of Air Quality  
100 North Senate Avenue  
MC 61-53 IGCN 1003  
Indianapolis, Indiana 46204-2251

no later than thirty-five (35) days prior to the intended test date. The protocol submitted by the Permittee does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

- (b) The Permittee shall notify IDEM, OAQ of the actual test date at least fourteen (14) days prior to the actual test date. The notification submitted by the Permittee does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).
- (c) Pursuant to 326 IAC 3-6-4(b), all test reports must be received by IDEM, OAQ not later than forty-five (45) days after the completion of the testing. An extension may be granted by IDEM, OAQ if the Permittee submits to IDEM, OAQ a reasonable written explanation not later than five (5) days prior to the end of the initial forty-five (45) day period.

### **Compliance Requirements [326 IAC 2-1.1-11]**

#### **C.9 Compliance Requirements [326 IAC 2-1.1-11]**

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The commissioner may require stack testing, monitoring, or reporting at any time to assure compliance with all applicable requirements by issuing an order under 326 IAC 2-1.1-11. Any monitoring or testing shall be performed in accordance with 326 IAC 3 or other methods approved by the commissioner or the U. S. EPA.

### **Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)]**

#### **C.10 Compliance Monitoring [326 IAC 2-7-5(3)][326 IAC 2-7-6(1)][40 CFR 64][326 IAC 3-8]**

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- (a) For new units:  
Unless otherwise specified in the approval for the new emission unit(s), compliance monitoring for new emission units shall be implemented on and after the date of initial start-up.
- (b) For existing units:  
Unless otherwise specified in this permit, for all monitoring requirements not already legally required, the Permittee shall be allowed up to ninety (90) days from the date of permit issuance to begin such monitoring. If, due to circumstances beyond the Permittee's control, any monitoring equipment required by this permit cannot be installed and operated no later than ninety (90) days after permit issuance, the Permittee may extend the compliance schedule related to the equipment for an additional ninety (90) days provided the Permittee notifies:

Indiana Department of Environmental Management  
Compliance and Enforcement Branch, Office of Air Quality  
100 North Senate Avenue  
MC 61-53 IGCN 1003  
Indianapolis, Indiana 46204-2251

in writing, prior to the end of the initial ninety (90) day compliance schedule, with full justification of the reasons for the inability to meet this date.

The notification which shall be submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

- (c) For monitoring required by CAM, at all times, the Permittee shall maintain the monitoring, including but not limited to, maintaining necessary parts for routine repairs of the monitoring equipment.
- (d) For monitoring required by CAM, except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the Permittee shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of this part, including data averages and calculations, or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

**C.11 Instrument Specifications [326 IAC 2-1.1-11] [326 IAC 2-7-5(3)] [326 IAC 2-7-6(1)]**

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- (a) When required by any condition of this permit, an analog instrument used to measure a parameter related to the operation of an air pollution control device shall have a scale such that the expected maximum reading for the normal range shall be no less than twenty percent (20%) of full scale. The analog instrument shall be capable of measuring values outside of the normal range.
- (b) The Permittee may request that the IDEM, OAQ approve the use of an instrument that does not meet the above specifications provided the Permittee can demonstrate that an alternative instrument specification will adequately ensure compliance with permit conditions requiring the measurement of the parameters.

**Corrective Actions and Response Steps [326 IAC 2-7-5][326 IAC 2-7-6]**

**C.12 Emergency Reduction Plans [326 IAC 1-5-2] [326 IAC 1-5-3]**

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Pursuant to 326 IAC 1-5-2 (Emergency Reduction Plans; Submission):

- (a) The Permittee shall maintain the most recently submitted written emergency reduction plans (ERPs) consistent with safe operating procedures.
- (b) Upon direct notification by IDEM, OAQ that a specific air pollution episode level is in effect, the Permittee shall immediately put into effect the actions stipulated in the approved ERP for the appropriate episode level. [326 IAC 1-5-3]

C.13 Risk Management Plan [326 IAC 2-7-5(11)] [40 CFR 68]

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If a regulated substance, as defined in 40 CFR 68, is present at a source in more than a threshold quantity, the Permittee must comply with the applicable requirements of 40 CFR 68.

C.14 Response to Excursions or Exceedances [40 CFR 64][326 IAC 3-8][326 IAC 2-7-5]  
[326 IAC 2-7-6]

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- (I) Upon detecting an excursion where a response step is required by the D Section, or an exceedance of a limitation, not subject to CAM, in this permit:
  - (a) The Permittee shall take reasonable response steps to restore operation of the emissions unit (including any control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing excess emissions.
  - (b) The response shall include minimizing the period of any startup, shutdown or malfunction. The response may include, but is not limited to, the following:
    - (1) initial inspection and evaluation;
    - (2) recording that operations returned or are returning to normal without operator action (such as through response by a computerized distribution control system); or
    - (3) any necessary follow-up actions to return operation to normal or usual manner of operation.
  - (c) A determination of whether the Permittee has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include, but is not limited to, the following:
    - (1) monitoring results;
    - (2) review of operation and maintenance procedures and records; and/or
    - (3) inspection of the control device, associated capture system, and the process.
  - (d) Failure to take reasonable response steps shall be considered a deviation from the permit.
  - (e) The Permittee shall record the reasonable response steps taken.
- (II)
  - (a) *CAM Response to excursions or exceedances.*
    - (1) Upon detecting an excursion or exceedance, subject to CAM, the Permittee shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). Such actions may include initial inspection and evaluation, recording that operations returned to normal

without operator action (such as through response by a computerized distribution control system), or any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable.

- (2) Determination of whether the Permittee has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include but is not limited to, monitoring results, review of operation and maintenance procedures and records, and inspection of the control device, associated capture system, and the process.
- (b) If the Permittee identifies a failure to achieve compliance with an emission limitation, subject to CAM, or standard, subject to CAM, for which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the Permittee shall promptly notify the IDEM, OAQ and, if necessary, submit a proposed significant permit modification to this permit to address the necessary monitoring changes. Such a modification may include, but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters.
  - (c) Based on the results of a determination made under paragraph (II)(a)(2) of this condition, the EPA or IDEM, OAQ may require the Permittee to develop and implement a Quality Improvement Plan (QIP). The Permittee shall develop and implement a QIP if notified to in writing by the EPA or IDEM, OAQ.
  - (d) Elements of a QIP:  
The Permittee shall maintain a written QIP, if required, and have it available for inspection. The plan shall conform to 40 CFR 64.8(b)(2).
  - (e) If a QIP is required, the Permittee shall develop and implement a QIP as expeditiously as practicable and shall notify the IDEM, OAQ if the period for completing the improvements contained in the QIP exceeds 180 days from the date on which the need to implement the QIP was determined.
  - (f) Following implementation of a QIP, upon any subsequent determination pursuant to paragraph (II)(a)(2) of this condition the EPA or the IDEM, OAQ may require that the Permittee make reasonable changes to the QIP if the QIP is found to have:
    - (1) Failed to address the cause of the control device performance problems;  
or
    - (2) Failed to provide adequate procedures for correcting control device performance problems as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions.
  - (g) Implementation of a QIP shall not excuse the Permittee from compliance with any existing emission limitation or standard, or any existing monitoring, testing, reporting or recordkeeping requirement that may apply under federal, state, or local law, or any other applicable requirements under the Act.

(h) *CAM recordkeeping requirements.*

- (1) The Permittee shall maintain records of monitoring data, monitor performance data, corrective actions taken, any written quality improvement plan required pursuant to paragraph (II)(c) of this condition and any activities undertaken to implement a quality improvement plan, and other supporting information required to be maintained under this condition (such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions). Section C - General Record Keeping Requirements of this permit contains the Permittee's obligations with regard to the records required by this condition.
- (2) Instead of paper records, the owner or operator may maintain records on alternative media, such as microfilm, computer files, magnetic tape disks, or microfiche, provided that the use of such alternative media allows for expeditious inspection and review, and does not conflict with other applicable recordkeeping requirements

C.15 Actions Related to Noncompliance Demonstrated by a Stack Test [326 IAC 2-7-5][326 IAC 2-7-6]

- (a) When the results of a stack test performed in conformance with Section C - Performance Testing, of this permit exceed the level specified in any condition of this permit, the Permittee shall submit a description of its response actions to IDEM, OAQ no later than seventy-five (75) days after the date of the test.
- (b) A retest to demonstrate compliance shall be performed no later than one hundred eighty (180) days after the date of the test. Should the Permittee demonstrate to IDEM, OAQ that retesting in one hundred eighty (180) days is not practicable, IDEM, OAQ may extend the retesting deadline.
- (c) IDEM, OAQ reserves the authority to take any actions allowed under law in response to noncompliant stack tests.

The response action documents submitted pursuant to this condition do require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

**Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]**

C.16 Emission Statement [326 IAC 2-7-5(3)(C)(iii)][326 IAC 2-7-5(7)][326 IAC 2-7-19(c)][326 IAC 2-6]

Pursuant to 326 IAC 2-6-3(a)(1), the Permittee shall submit by July 1 of each year an emission statement covering the previous calendar year. The emission statement shall contain, at a minimum, the information specified in 326 IAC 2-6-4(c) and shall meet the following requirements:

- (1) Indicate estimated actual emissions of all pollutants listed in 326 IAC 2-6-4(a);
- (2) Indicate estimated actual emissions of regulated pollutants as defined by 326 IAC 2-7-1(33) ("Regulated pollutant, which is used only for purposes of Section 19 of this rule") from the source, for purpose of fee assessment.

The statement must be submitted to:

Indiana Department of Environmental Management  
Technical Support and Modeling Section, Office of Air Quality  
100 North Senate Avenue  
MC 61-50 IGCN 1003  
Indianapolis, Indiana 46204-2251

The emission statement does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

C.17 General Record Keeping Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-6]  
[326 IAC 2-2][326 IAC 2-3]

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(a) Records of all required monitoring data, reports and support information required by this permit shall be retained for a period of at least five (5) years from the date of monitoring sample, measurement, report, or application. Support information includes the following, where applicable:

- (AA) All calibration and maintenance records.
- (BB) All original strip chart recordings for continuous monitoring instrumentation.
- (CC) Copies of all reports required by the Part 70 permit.

Records of required monitoring information include the following, where applicable:

- (AA) The date, place, as defined in this permit, and time of sampling or measurements.
- (BB) The dates analyses were performed.
- (CC) The company or entity that performed the analyses.
- (DD) The analytical techniques or methods used.
- (EE) The results of such analyses.
- (FF) The operating conditions as existing at the time of sampling or measurement.

These records shall be physically present or electronically accessible at the source location for a minimum of three (3) years. The records may be stored elsewhere for the remaining two (2) years as long as they are available upon request. If the Commissioner makes a request for records to the Permittee, the Permittee shall furnish the records to the Commissioner within a reasonable time.

(b) Unless otherwise specified in this permit, for all record keeping requirements not already legally required, the Permittee shall be allowed up to ninety (90) days from the date of permit issuance or the date of initial start-up, whichever is later, to begin such record keeping.

(c) If there is a reasonable possibility (as defined in 326 IAC 2-2-8 (b)(6)(A), 326 IAC 2-2-8 (b)(6)(B), 326 IAC 2-3-2 (l)(6)(A), and/or 326 IAC 2-3-2 (l)(6)(B)) that a "project" (as defined in 326 IAC 2-2-1(oo) and/or 326 IAC 2-3-1(jj)) at an existing emissions unit, other than projects at a source with a Plantwide Applicability Limitation (PAL), which is not part of a "major modification" (as defined in 326 IAC 2-2-1(dd) and/or 326 IAC 2-3-1(y)) may result in significant emissions increase and the Permittee elects to utilize the "projected actual emissions" (as defined in 326 IAC 2-2-1(pp) and/or 326 IAC 2-3-1(kk)), the Permittee shall comply with following:

(1) Before beginning actual construction of the "project" (as defined in 326 IAC 2-2-1(oo) and/or 326 IAC 2-3-1(jj)) at an existing emissions unit, document and maintain the following records:

- (A) A description of the project.
- (B) Identification of any emissions unit whose emissions of a regulated new source review pollutant could be affected by the project.
- (C) A description of the applicability test used to determine that the project is not a major modification for any regulated NSR pollutant, including:
  - (i) Baseline actual emissions;



- (ii) Projected actual emissions;
  - (iii) Amount of emissions excluded under section 326 IAC 2-2-1(pp)(2)(A)(iii) and/or 326 IAC 2-3-1 (kk)(2)(A)(iii); and
  - (iv) An explanation for why the amount was excluded, and any netting calculations, if applicable.
- (d) If there is a reasonable possibility (as defined in 326 IAC 2-2-8 (b)(6)(A) and/or 326 IAC 2-3-2 (l)(6)(A)) that a "project" (as defined in 326 IAC 2-2-1(oo) and/or 326 IAC 2-3-1(jj)) at an existing emissions unit, other than projects at a source with a Plantwide Applicability Limitation (PAL), which is not part of a "major modification" (as defined in 326 IAC 2-2-1(dd) and/or 326 IAC 2-3-1(y)) may result in significant emissions increase and the Permittee elects to utilize the "projected actual emissions" (as defined in 326 IAC 2-2-1(pp) and/or 326 IAC 2-3-1(kk)), the Permittee shall comply with following:
- (1) Monitor the emissions of any regulated NSR pollutant that could increase as a result of the project and that is emitted by any existing emissions unit identified in (1)(B) above; and
  - (2) Calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of five (5) years following resumption of regular operations after the change, or for a period of ten (10) years following resumption of regular operations after the change if the project increases the design capacity of or the potential to emit that regulated NSR pollutant at the emissions unit.

C.18 General Reporting Requirements [326 IAC 2-7-5(3)(C)] [326 IAC 2-1.1-11]  
[326 IAC 2-2][326 IAC 2-3] [40 CFR 64][326 IAC 3-8]

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- (a) The Permittee shall submit the attached Quarterly Deviation and Compliance Monitoring Report or its equivalent. Proper notice submittal under Section B - Emergency Provisions satisfies the reporting requirements of this paragraph. Any deviation from permit requirements, the date(s) of each deviation, the cause of the deviation, and the response steps taken must be reported except that a deviation required to be reported pursuant to an applicable requirement that exists independent of this permit, shall be reported according to the schedule stated in the applicable requirement and does not need to be included in this report. This report shall be submitted not later than thirty (30) days after the end of the reporting period. The Quarterly Deviation and Compliance Monitoring Report shall include a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35). A deviation is an exceedance of a permit limitation or a failure to comply with a requirement of the permit.

On and after the date by which the Permittee must use monitoring that meets the requirements of 40 CFR Part 64 and 326 IAC 3-8, the Permittee shall submit CAM reports to the IDEM, OAQ.

A report for monitoring under 40 CFR Part 64 and 326 IAC 3-8 shall include, at a minimum, the information required under paragraph (a) of this condition and the following information, as applicable:

- (1) Summary information on the number, duration and cause (including unknown cause, if applicable) of excursions or exceedances, as applicable, and the corrective actions taken;

- (2) Summary information on the number, duration and cause (including unknown cause, if applicable) for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks, if applicable); and
- (3) A description of the actions taken to implement a QIP during the reporting period as specified in Section C - Response to Excursions or Exceedances. Upon completion of a QIP, the owner or operator shall include in the next summary report documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances occurring.

The Permittee may combine the Quarterly Deviation and Compliance Monitoring Report and a report pursuant to 40 CFR 64 and 326 IAC 3-8.

- (b) The address for report submittal is:  
  
Indiana Department of Environmental Management  
Compliance and Enforcement Branch, Office of Air Quality  
100 North Senate Avenue  
MC 61-53 IGCN 1003  
Indianapolis, Indiana 46204-2251
- (c) Unless otherwise specified in this permit, any notice, report, or other submission required by this permit shall be considered timely if the date postmarked on the envelope or certified mail receipt, or affixed by the shipper on the private shipping receipt, is on or before the date it is due. If the document is submitted by any other means, it shall be considered timely if received by IDEM, OAQ on or before the date it is due.
- (d) Reporting periods are based on calendar years, unless otherwise specified in this permit. For the purpose of this permit "calendar year" means the twelve (12) month period from January 1 to December 31 inclusive.
- (e) If the Permittee is required to comply with the recordkeeping provisions of (d) in Section C - General Record Keeping Requirements for any "project" (as defined in 326 IAC 2-2-1 (oo) and/or 326 IAC 2-3-1 (jj)) at an existing emissions unit, and the project meets the following criteria, then the Permittee shall submit a report to IDEM, OAQ:
  - (1) The annual emissions, in tons per year, from the project identified in (c)(1) in Section C- General Record Keeping Requirements exceed the baseline actual emissions, as documented and maintained under Section C- General Record Keeping Requirements (c)(1)(C)(i), by a significant amount, as defined in 326 IAC 2-2-1 (ww) and/or 326 IAC 2-3-1 (pp), for that regulated NSR pollutant, and
  - (2) The emissions differ from the preconstruction projection as documented and maintained under Section C - General Record Keeping Requirements (c)(1)(C)(ii).
- (f) The report for project at an existing emissions *unit* shall be submitted no later than sixty (60) days after the end of the year and contain the following:
  - (1) The name, address, and telephone number of the major stationary source.
  - (2) The annual emissions calculated in accordance with (d)(1) and (2) in Section C - General Record Keeping Requirements.

- (3) The emissions calculated under the actual-to-projected actual test stated in 326 IAC 2-2-2(d)(3) and/or 326 IAC 2-3-2(c)(3).
- (4) Any other information that the Permittee wishes to include in this report such as an explanation as to why the emissions differ from the preconstruction projection.

Reports required in this part shall be submitted to:

Indiana Department of Environmental Management  
Compliance and Enforcement Branch, Office of Air Quality  
100 North Senate Avenue  
MC 61-53 IGCN 1003  
Indianapolis, Indiana 46204-2251

- (g) The Permittee shall make the information required to be documented and maintained in accordance with (c) in Section C- General Record Keeping Requirements available for review upon a request for inspection by IDEM, OAQ. The general public may request this information from the IDEM, OAQ under 326 IAC 17.1.

### **Stratospheric Ozone Protection**

#### **C.19 Compliance with 40 CFR 82 and 326 IAC 22-1**

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Pursuant to 40 CFR 82 (Protection of Stratospheric Ozone), Subpart F, except as provided for motor vehicle air conditioners in Subpart B, the Permittee shall comply with applicable standards for recycling and emissions reduction.

## SECTION D.1 EMISSIONS UNIT OPERATION CONDITIONS

### Emissions Unit Description:

- (a) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 1, installed in 1967, using #2 fuel oil for startup, shutdown, and stabilization purposes, with a nominal heat input capacity of 4,802 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, a flue gas desulfurization (FGD) system for control of SO<sub>2</sub>, and exhausting to stack 1. Stack 1 has continuous emissions monitors (CEMs) for nitrogen oxides (NO<sub>x</sub>), sulfur dioxide (SO<sub>2</sub>), and particulate matter (PM). Boiler No. 1 was configured with a low NO<sub>x</sub> burner in 1993. Selective Catalytic Oxidation (SCR) to control NO<sub>x</sub>, and Dry Sorbent Injection System to Control SO<sub>3</sub> constructed in 2015. The Boiler is equipped with a PM CEMS, SO<sub>2</sub> CEMS, NO<sub>x</sub> CEMS and Hg CEMS.

[Under NESHAP Subpart UUUUU, this unit is part of an affected source.]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

### Emission Limitations and Standards [326 IAC 2-7-5(1)]

#### D.1.1 Particulate Emission Limitations for Sources of Indirect Heating [326 IAC 6-2-3]

The Particulate Matter emissions from Boiler No. 1 shall be limited to 0.227 lbs/MMBtu. Compliance with this limit satisfies the requirements of 326 IAC 6-2-3 (Particulate Emission Limitations for Sources of Indirect Heating). This emissions limit is based on the historic Particulate Matter emission limit established under 326 IAC 6-2-3.

#### D.1.2 Sulfur Dioxide (SO<sub>2</sub>) [326 IAC 7-4-8] [326 IAC 7-2-1]

Pursuant to 326 IAC 7-4-8 (Vermillion County Sulfur Dioxide Emission Limitations), the SO<sub>2</sub> emissions from Boiler No. 1 shall not exceed 4.40 pounds per million Btu (lbs/MMBtu), demonstrated using a thirty (30) day weighted rolling average. This limitation will ensure that SO<sub>2</sub> emissions do not exceed the amount assumed in the modeling analysis performed for the Vermillion County SO<sub>2</sub> SIP limits.

#### D.1.3 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

A Preventive Maintenance Plan (PMP) is required for this unit and its control device. Section B - Preventive Maintenance Plan contains the Permittee's obligations with regard to the preventive maintenance plan required by this condition.

### Compliance Determination Requirements [326 IAC 2-7-5(1)]

#### D.1.4 Operation of Electrostatic Precipitator and Flue Gas Desulfurization (FGD) [326 IAC 2-7-6(6)]

- (a) Except as otherwise provided by statute or rule or in this permit, the electrostatic precipitator shall be operated at all times that Boiler No. 1 is in operation and combusting solid fuel or any combination of solid fuels or other fuels.
- (b) Except as otherwise provided by statute or rule or in this permit, the flue gas desulfurization (FGD) system shall be operated as needed to maintain compliance with applicable SO<sub>2</sub> emission limits.

#### D.1.5 Reserved

#### D.1.6 Continuous Emissions Monitoring [326 IAC 3-5] [326 IAC 2-7-6(1),(6)]

- (a) Pursuant to 326 IAC 3-5 (Continuous Monitoring of Emissions) continuous emission monitoring systems for Boiler No. 1 shall be calibrated, maintained, and operated for

measuring PM, SO<sub>2</sub>, NO<sub>x</sub>, and Hg which meet all applicable performance specifications of 326 IAC 3-5-2.

- (1) If the CEM is required for monitoring NO<sub>x</sub> or SO<sub>2</sub> emissions pursuant to 40 CFR 75 (Title IV Acid Rain program) or 326 IAC 24 (SO<sub>2</sub> and NO<sub>x</sub> Trading Program), the Permittee shall comply with the relevant requirements of 40 CFR 75 Subpart D- Missing Data Substitution Procedures.
  - (2) If the CEM is not used to monitor NO<sub>x</sub> or SO<sub>2</sub> emissions pursuant to 40 CFR 75 or 326 IAC 24 (SO<sub>2</sub> and NO<sub>x</sub> Trading Program), then supplemental or intermittent monitoring of the parameter shall be implemented as specified in Section D of this permit until such time as the emission monitor system is back in operation.
- (b) All continuous emissions monitoring systems are subject to monitor system certification requirements pursuant to 326 IAC 3-5-3.
- (c) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous emission monitoring system pursuant to 326 IAC 3-5

**D.1.7 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 2-7-5(A)] [326 IAC 2-7-6] [326 IAC 7-2]**

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- (a) Pursuant to 326 IAC 7-2-1(c), the Permittee shall demonstrate that the sulfur dioxide emissions from Unit 1 do not exceed the equivalents of the limits specified in Conditions D.1.2 (Sulfur Dioxide (SO<sub>2</sub>)) using a thirty (30) day rolling weighted average.
- (b) If using CEMS, continuous emission monitoring data collected and reported pursuant to 326 IAC 3-5 shall be used as the means for determining compliance with the emission limitations in 326 IAC 7.

**D.1.8 Particulate Matter (PM) Continuous Emission Monitoring System [326 IAC 3-5] [326 IAC 2-7-5(3)(A)(iii)]**

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The Permittee shall install, certify, maintain, and operate a CEMS measuring PM emissions discharged from Boiler No. 1 scrubbed stack to the atmosphere and record the output of the system as specified in paragraphs (a) through (d):

- (a) The PM CEMS shall be installed, certified, operated, and maintained pursuant to 40 CFR Part 60, Appendix B, Performance Specification #11 and 40 CFR 60.13(e).
- (b) Compliance with the applicable particulate emission limitation in Condition D.1.1 shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emissions concentrations using the continuous monitoring system outlet data.
- (c) For purposes of demonstrating compliance with the particulate emission limitation in Condition D.1.1, the Permittee shall adjust to 5% any measured carbon dioxide (CO<sub>2</sub>) values that are below 5%.
- (d) In the event that a breakdown of the continuous monitoring system occurs, a record shall be made of the times and reasons for the breakdown and efforts made to correct the problem.
- (e) Nothing in this permit shall excuse the Permittee from complying with the requirement to operate a continuous emissions monitoring system pursuant to 326 IAC 3.

**Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)]**

**D.1.9 Reserved**

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#### D.1.10 Reserved

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#### D.1.11 Sulfur Dioxide Continuous Emissions Monitoring (CEMS) Equipment Downtime

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- (a) In the event that a breakdown of a SO<sub>2</sub> continuous emissions monitoring system (CEMS) occurs, a record shall be made of the time and reason for the breakdown and efforts made to correct the problem.
- (b) Whenever a SO<sub>2</sub> continuous emissions monitoring system (CEMS) is malfunctioning or is down for maintenance or repairs for a period of twenty-four (24) hours or more and a backup SO<sub>2</sub> CEMS is not online within twenty-four (24) hours of shutdown or malfunction of the primary SO<sub>2</sub> CEMS, the Permittee shall comply with the following:
  - (1) The Permittee shall monitor and record the boiler load, recirculation pH, slurry feed rate, and number of recirculation pumps in service, to demonstrate that the operation of the scrubber continues in a manner typical for the boiler load and sulfur content of the coal fired.
  - (2) Flue gas desulfurization (FGD) parametric monitoring readings shall be recorded at least twice per day until the primary CEMS or a backup CEMS is brought online.
- (c) Parametric monitoring shall begin not more than twenty-four (24) hours after the start of the malfunction or down time at least twice per day during normal operations, with at least four (4) hours between each set of readings, until a SO<sub>2</sub>-CEMS is online.

#### D.1.12 PM Continuous Emissions Monitoring (CEMS) Equipment Downtime

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- (a) In the event that a breakdown of a PM continuous emissions monitoring system (CEMS) occurs, a record shall be made of the time and reason of the breakdown and efforts made to correct the problem.
- (b) Whenever a PM continuous emissions monitoring system (CEMS) is malfunctioning or is down for maintenance or repairs for a period of twenty-four (24) hours or more and a backup PM CEMS is not online within twenty-four (24) hours of shutdown or malfunction of the primary PM CEMS, the Permittee shall comply with the following:
  - (1) The ability of the electrostatic precipitator to control particulate matter emissions shall be monitored at least twice per day when Boiler No. 1 is in operation by measuring and recording the following:
    - a) The primary and secondary currents of the T-R sets
    - b) The primary and secondary voltages of the T-R sets
    - c) Number of TR sets in service
- (c) Parametric monitoring shall begin not more than twenty-four (24) hours after the start of the malfunction or down time at least twice per day during normal operations, with at least four (4) hours between each set of readings, until a PM -CEMS is online.

### **Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]**

#### D.1.13 Record Keeping Requirements for CEMS [326 IAC 2-7-5(3)(B)] [326 IAC 3-5]

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- (a) To document the compliance status with Conditions D.1.1, D.1.8, and D.1.12, the Permittee shall maintain records in accordance with (1) through (2) below.
  - (1) PM CEMS data to measure PM pursuant to 326 IAC 3-5.

- (2) All ESP parametric monitoring readings taken during any period of CEMs downtime, in accordance with Condition D.1.12.
- (b) To document the compliance status with Conditions D.1.2, D.1.6, D.1.7 and D.1.11, the Permittee shall maintain records in accordance with (1) and (2) below. Records shall be complete and sufficient to establish compliance with the SO<sub>2</sub> limits as required in Conditions D.1.2.
  - (1) All SO<sub>2</sub> continuous emissions monitoring data pursuant to 326 IAC 3-5-6 and 326 IAC 7-2-1(g).
  - (2) All flue gas desulfurization (FGD) system parametric monitoring readings taken during any periods of CEMS downtime, in accordance with Condition D.1.11.
- (c) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

#### D.1.14 Reporting Requirements

- (a) Pursuant to 326 IAC 3-5-7(c) and (d), a quarterly excess emissions report of the information to document the compliance status with conditions D.1.1 and D.1.2 shall be submitted not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.
- (b) Pursuant to 326 IAC 3-5-5(f), a quarterly report of the continuous emissions monitoring system performance audits shall be submitted not later than thirty (30) days following the end of each calendar quarter and within forty five (45) calendar days after the completion of the test for the relative accuracy test audits. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.
- (c) Pursuant to 326 IAC 3-5-7(c), a quarterly report of the continuous monitoring system instrument downtime shall be submitted not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

## SECTION D.2 EMISSIONS UNIT OPERATION CONDITIONS

### Emissions Unit Description:

- (b) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 2, installed in 1968, using #2 fuel oil for startup, shutdown, and stabilization purposes, with a nominal heat input capacity of 4,802 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, a flue gas desulfurization (FGD) system for control of SO<sub>2</sub>, and exhausting to stack 2. Stack 2 has continuous emissions monitors (CEMs) for nitrogen oxides (NO<sub>x</sub>), sulfur dioxide (SO<sub>2</sub>), and particulate matter (PM). Boiler No. 2 was configured with a low NO<sub>x</sub> burner in 1993. Selective Catalytic Oxidation (SCR) to control NO<sub>x</sub>, and Dry Sorbent Injection System to Control SO<sub>3</sub> constructed in 2015. The Boiler is equipped with a PM CEMS, SO<sub>2</sub> CEMS, NO<sub>x</sub> CEMS and Hg CEMS.

[Under NESHAP Subpart UUUUU, this unit is part of an affected source.]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

### Emission Limitations and Standards [326 IAC 2-7-5(1)]

#### D.2.1 Particulate Emission Limitations for Sources of Indirect Heating [326 IAC 6-2-3]

The Particulate Matter emissions from Boiler No. 2 shall be limited to 0.227 lbs/MMBtu. Compliance with this limit satisfies the requirements of 326 IAC 6-2-3 (Particulate Emission Limitations for Sources of Indirect Heating). This limit is based on the historic particulate matter emissions limit established under 326 IAC 6-2-3.

#### D.2.2 Sulfur Dioxide (SO<sub>2</sub>) [326 IAC 7-4-8] [326 IAC 7-2-1]

Pursuant to 326 IAC 7-4-8 (Vermillion County Sulfur Dioxide Emission Limitations), the SO<sub>2</sub> emissions from Boiler No. 2 shall not exceed 4.40 pounds per million Btu (lbs/MMBtu), demonstrated using a thirty (30) day rolling weighted average. This limitation will ensure that SO<sub>2</sub> emissions do not exceed the amount assumed in the modeling analysis performed for the Vermillion County SO<sub>2</sub> SIP limits.

#### D.2.3 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

A Preventive Maintenance Plan (PMP) is required for this unit and its control device. Section B - Preventive Maintenance Plan contains the Permittee's obligations with regard to the preventive maintenance plan required by this condition.

### Compliance Determination Requirements [326 IAC 2-7-5(1)]

#### D.2.4 Operation of Electrostatic Precipitator and Flue Gas Desulfurization (FGD) [326 IAC 2-7-6(6)]

- (a) Except as otherwise provided by statute or rule or in this permit, the electrostatic precipitator shall be operated at all times that Boiler No. 2 is in operation and combusting solid fuel or any combination of solid fuels or other fuels.
- (b) Except as otherwise provided by statute or rule or in this permit, the flue gas desulfurization (FGD) system shall be operated as needed to maintain compliance with applicable SO<sub>2</sub> emission limits.

#### D.2.5 Reserved

#### D.2.6 Continuous Emissions Monitoring [326 IAC 3-5] [326 IAC 2-7-6(1),(6)]

- (a) Pursuant to 326 IAC 3-5 (Continuous Monitoring of Emissions) continuous emission monitoring systems for Boiler No.2 shall be calibrated, maintained, and operated for



measuring PM, SO<sub>2</sub>, NO<sub>x</sub>, and Hg which meet all applicable performance specifications of 326 IAC 3-5-2.

- (1) If the CEM is required for monitoring NO<sub>x</sub> or SO<sub>2</sub> emissions pursuant to 40 CFR 75 (Title IV Acid Rain program) or 326 IAC 24 (SO<sub>2</sub> and NO<sub>x</sub> Trading Program), the Permittee shall comply with the relevant requirements of 40 CFR 75 Subpart D- Missing Data Substitution Procedures.
  - (2) If the CEM is not used to monitor NO<sub>x</sub> or SO<sub>2</sub> emissions pursuant to 40 CFR 75 or 326 IAC 24 (SO<sub>2</sub> and NO<sub>x</sub> Trading Program), then supplemental or intermittent monitoring of the parameter shall be implemented as specified in Section D of this permit until such time as the emission monitor system is back in operation.
- (b) All continuous emissions monitoring systems are subject to monitor system certification requirements pursuant to 326 IAC 3-5-3.
- (c) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous emission monitoring system pursuant to 326 IAC 3-5

D.2.7 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 2-7-5(A)] [326 IAC 2-7-6] [326 IAC 7-2]

- (a) Pursuant to 326 IAC 7-2-1(c), the Permittee shall demonstrate that the sulfur dioxide emissions from Unit 2 do not exceed the equivalents of the limits specified in Conditions D.2.2 (Sulfur Dioxide (SO<sub>2</sub>)) using a thirty (30) day rolling weighted average.
- (b) If using CEMS, continuous emission monitoring data collected and reported pursuant to 326 IAC 3-5 shall be used as the means for determining compliance with the emission limitations in 326 IAC 7.

D.2.8 Particulate Matter (PM) Continuous Emission Monitoring System [326 IAC 3-5] [326 IAC 2-7-5(3)(A)(iii)]

The Permittee shall install, certify, maintain, and operate a CEMS measuring PM emissions discharged from Boiler No. 2 scrubbed stack to the atmosphere and record the output of the system as specified in paragraphs (a) through (e):

- (a) The PM CEMS shall be installed, certified, operated, and maintained pursuant to 40 CFR Part 60, Appendix B, Performance Specification #11 and 40 CFR 60.13(e).
- (b) Compliance with the applicable particulate emission limitation in Condition D.2.1 shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emissions concentrations using the continuous monitoring system outlet data.
- (c) For purposes of demonstrating compliance with the particulate emission limitation in Condition D.2.1, the Permittee shall adjust to 5% any measured carbon dioxide (CO<sub>2</sub>) values that are below 5%.
- (d) In the event that a breakdown of the continuous monitoring system occurs, a record shall be made of the times and reasons for the breakdown and efforts made to correct the problem.
- (e) Nothing in this permit shall excuse the Permittee from complying with the requirement to operate the continuous emissions monitoring system pursuant to 326 IAC 3.

D.2.9 Reserved

D.2.10 Reserved

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**Compliance Monitoring Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]**

**D.2.11 Sulfur Dioxide Continuous Emissions Monitoring (CEMS) Equipment Downtime**

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- (a) In the event that a breakdown of a SO<sub>2</sub> continuous emissions monitoring system (CEMS) occurs, a record shall be made of the time and reason for the breakdown and efforts made to correct the problem.
- (b) Whenever a SO<sub>2</sub> continuous emissions monitoring system (CEMS) is malfunctioning or is down for maintenance or repairs for a period of twenty-four (24) hours or more and a backup SO<sub>2</sub> CEMS is not online within twenty-four (24) hours of shutdown or malfunction of the primary SO<sub>2</sub> CEMS, the Permittee shall comply with the following:
  - (1) The Permittee shall monitor and record the boiler load, recirculation pH, slurry feed rate, and number of recirculation pumps in service, to demonstrate that the operation of the scrubber continues in a manner typical for the boiler load and sulfur content of the coal fired.
  - (2) Flue gas desulfurization (FGD) parametric monitoring readings shall be recorded at least twice per day until the primary CEMS or a backup CEMS is brought online.
- (c) Parametric monitoring shall begin not more than twenty-four (24) hours after the start of the malfunction or down time at least twice per day during normal operations, with at least four (4) hours between each set of readings, until a SO<sub>2</sub>-CEMS is online.

**D.2.12 PM Continuous Emissions Monitoring (CEMS) Equipment Downtime**

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- (a) In the event that a breakdown of a PM continuous emissions monitoring system (CEMS) occurs, a record shall be made of the time and reason of the breakdown and efforts made to correct the problem.
- (b) Whenever a PM continuous emissions monitoring system (CEMS) is malfunctioning or is down for maintenance or repairs for a period of twenty-four (24) hours or more and a backup PM CEMS is not online within twenty-four (24) hours of shutdown or malfunction of the primary PM CEMS, the Permittee shall comply with the following:
  - (1) The ability of the electrostatic precipitator to control particulate matter emissions shall be monitored at least twice per day when Boiler No. 2 is in operation by measuring and recording the following:
    - a) The primary and secondary currents of the T-R sets.
    - b) The primary and secondary voltages of the T-R sets
    - c) Number of TR sets in service
- (c) Parametric monitoring shall begin not more than twenty-four (24) hours after the start of the malfunction or down time at least twice per day during normal operations, with at least four (4) hours between each set of readings, until a PM -CEMS is online.

**Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]**

**D.2.13 Record Keeping Requirements for CEMS [326 IAC 2-7-5(3)(B)] [326 IAC 3-5]**

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- (a) To document the compliance status with requirements in Condition D.2.1, D.2.8 and D.2.12, the Permittee shall maintain records in accordance with (1) and (2) below.
  - (1) PM CEMS data to measure PM pursuant to 326 IAC 3-5.

- (2) All ESP Parametric monitoring readings taken during any periods of CEMS downtime, in accordance with Condition D.2.12.
- (b) To document the compliance status with Conditions D.2.2, D.2.6, D.2.7 and D.2.11, the Permittee shall maintain records in accordance with (1) and (2) below. Records shall be complete and sufficient to establish compliance with the SO<sub>2</sub> limits as required in Conditions D.2.2.
  - (1) All SO<sub>2</sub> continuous emissions monitoring data pursuant to 326 IAC 3-5-6.
  - (2) All flue gas desulfurization (FGD) system parametric monitoring readings taken during periods of CEMS downtime, in accordance with Condition D.2.11.
- (c) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

#### D.2.14 Reporting Requirements

- (a) Pursuant to 326 IAC 3-5-7(c) and (d), a quarterly excess emissions report of the information to document the compliance status with conditions D.2.1 and D.2.2 shall be submitted not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.
- (b) Pursuant to 326 IAC 3-5-5(f), a quarterly report of the continuous emissions monitoring system performance audits shall be submitted not later than thirty (30) days following the end of each calendar quarter and within forty five (45) calendar days after the completion of the test for the relative accuracy test audits. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.
- (c) Pursuant to 326 IAC 3-5-7(c), a quarterly report of the continuous monitoring system instrument downtime shall be submitted not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

**SECTION D.3**

**Reserved**

## SECTION D.4 EMISSIONS UNIT OPERATION CONDITIONS

### Emissions Unit Description:

- (g) A dual conveyor coal processing system, constructed in 1968, with a nominal throughput of 1900 tons of coal per hour (950 tons of coal per hour each side), consisting of the following equipment:
- (1) One (1) railcar unloading station with a drop point to two (2) hoppers, with a capacity of 1900 tons, identified as DP-1, with the drop point enclosed with emissions uncontrolled, and exhausting to the ambient air.
  - (2) One (1) storage area having a nominal storage capacity including the active piles of 982,800 tons, with fugitive emissions controlled as needed by a watering truck.
  - (3) One (1) enclosed hopper, with a drop point to a conveyor identified as DP-2, with a capacity of 1900 tons controlled by an enclosure and a water spray dust suppression system as needed and exhausting to the ambient air.
  - (4) One (1) enclosed hopper and two (2) reclaim feeders, with a capacity of 1900 tons with underground drop points identified as DP-10 and DP-12, with emissions controlled by the underground enclosure, and routed to the conveyor system.
  - (5) An enclosed dual conveyor system, with six (6) drop points identified as DP-3 through DP-6, DP-8, and DP-13, with a capacity of 1900 tons controlled by enclosure and water spray dust suppression system as needed, exhausting to ambient air.
  - (6) An enclosed conveyor system with drop point identified as DP-9, with a capacity of 1900 tons controlled by a telescoping chute.
  - (7) Coal bunker, with one (1) drop point identified as DP-7, with a capacity of 1900 tons, controlled by a rotoclone.

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

### Emission Limitations and Standards [326 IAC 2-7-5(1)]

#### D.4.1 Particulate Emission Limitations for Manufacturing Processes [326 IAC 6-3-2]

Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes), the particulate emission rate from the coal processing drop points, coal scale exhausts, and coal bunkers shall not exceed 86.19 pounds per hour when operating at a process weight rate of 1900 tons per hour. This is determined by the following equation:

Interpolation and extrapolation of the data for the process weight rate in excess of sixty thousand (60,000) pounds per hour shall be accomplished by use of the equation:

$$E = 55.0 P^{0.11} - 40 \quad \text{where } E = \text{rate of emission in pounds per hour and} \\ P = 950 \text{ (process weight rate in tons per hour)}$$

When the process weight exceeds two hundred (200) tons/hour, the maximum allowable emission may exceed 86.19 pounds per hour, provided the concentration of particulate matter in the discharge gases to the atmosphere is less than 0.10 pounds per one thousand (1,000) pounds of gases.

**D.4.2 Preventive Maintenance Plan [326 IAC 2-7-5(13)]**

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A Preventive Maintenance Plan (PMP) is required for this unit and its control device. Section B - Preventive Maintenance Plan contains the Permittee's obligations with regard to the preventive maintenance plan required by this condition.

**Compliance Determination Requirements [326 IAC 2-7-5(1)]**

**D.4.3 Particulate Control [326 IAC 2-7-6(6)]**

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- (a) Except as otherwise provided by statute or rule or in this permit, in order to comply with Section C - Opacity and Condition D.4.1, the rotoclone shall be in operation at all times the coal bunkers are in operation.
- (b) In order to ensure compliance with Condition C.2, the Permittee shall minimize fugitive dust from the storage pile areas and open drop points from hoppers and conveyors through the use of water to suppress fugitive dust from these areas when necessary and weather permitting.

**Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)]**

**D.4.4 Visible Emissions Notations [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]**

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- (a) Visible emission notations of the drop point, identified as DP-9, shall be performed once per week during normal daylight operations when transferring coal. A trained employee shall record whether emissions are normal or abnormal.
- (b) For processes operated continuously, "normal" means those conditions prevailing, or expected to prevail, eighty percent (80%) of the time the process is in operation, not counting startup or shut down time.
- (c) In the case of batch or discontinuous operations, readings shall be taken during that part of the operation that would normally be expected to cause the greatest emissions.
- (d) A trained employee is an employee who has worked at the plant at least one (1) month and has been trained in the appearance and characteristics of normal visible emissions for that specific process.
- (e) If abnormal emissions are observed, the Permittee shall take reasonable response steps. Failure to take response steps, shall be considered a deviation of this permit. Section C – Response to Excursions or Exceedances contains the Permittee's obligations with regard to responding to the reasonable response steps required by this condition.

**Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]**

**D.4.5 Record Keeping Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]**

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- (a) To document the compliance status with condition D.4.4, the Permittee shall maintain records of the weekly visible emission notations of the drop point, identified as DP-9. The Permittee shall include in its records when a visible emission notation is not taken and the reason for the lack of visible emission notation (e.g., the unit did not operate that day).
- (b) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

## SECTION D.5 EMISSIONS UNIT OPERATION CONDITIONS

### Emissions Unit Description:

- (h) One (1) limestone handling and storage system for the flue gas desulfurization system, constructed in 2006, with a maximum throughput rate of 1,000 tons per hour, consisting of the following:
- (1) One (1) railcar/truck unloading operation with a maximum capacity of 1,000 tons per hour, controlled by fog dust suppression, and exhausting to emission point EP-L1.
  - (2) Two (2) hoppers, each with a maximum capacity of 500 tons per hour controlled by fog dust suppression and exhausting to emission point EP-L2.
  - (3) Two (2) belt feeders, identified as LHBF-1 and LHBF-2 each with a maximum capacity of 500 tons per hour, controlled by fog dust suppression, and exhausting to emission point EP-L2.
  - (4) One (1) conveyor, identified as LH-1 controlled by a telescopic chute, and exhausting to emission point EP-L3. Under NSPS, Subpart OOO, this unit is considered a belt conveyor.
  - (5) One (1) active limestone stockout pile with a maximum capacity of 7,700 tons.
  - (6) One (1) inactive limestone storage pile with a maximum capacity of 45,000 tons.
  - (7) Two (2) reclaim hoppers each with a maximum capacity of 200 tons per hour, controlled by fog dust suppression, and exhausting to emission point EP-L4.
  - (8) Two (2) belt feeders, identified as LHBF-3 and LHBF-4 each with a maximum capacity of 200 tons per hour, controlled by fog dust suppression, and exhausting to emission point EP-L4.
  - (9) One (1) conveyor, identified as LH-2 with a maximum capacity of 400 tons per hour, controlled by fog dust suppression. The emissions exhaust out the general building vents, identified as emission point EP-L18a and EP-L18b. Under NSPS, Subpart OOO, this unit is considered a belt conveyor.
  - (10) One (1) reversible conveyor, identified as LH-3 with a maximum capacity of 400 tons per hour, controlled by fog dust suppression. The emissions exhaust out the general building vents, identified as emission points EP-L18a and EP-L18b. Under NSPS, Subpart OOO, this unit is considered a belt conveyor.
  - (11) Two (2) day bins each with a maximum throughput rate of 400 tons per hour. Each bin is equipped with a Baghouse to control particulate emissions. Filter F-L1 and F-L2 exhaust to EP-L16 and EP-L17, respectively. Under NSPS, Subpart OOO, these units are considered storage bins.
  - (12) Two (2) wet ball mills each with a maximum capacity of 51 tons of limestone slurry per hour. Under NSPS, Subpart OOO, these units are considered grinding mills.
- (i) One (1) gypsum handling and storage system, constructed in 2006, consisting of the following:
- (1) One (1) wet gypsum conveying system with a maximum throughput rate of 150 tons per hour.

- (2) Two (2) gypsum stock out piles Gypsum can be stocked out to an outside pile or a pile located in the gypsum stock out building. The maximum gypsum storage capacity is 10,400 tons.
  - (3) One (1) emergency gypsum stockout pile with a maximum capacity of 2,600 tons.
  - (4) One (1) dry gypsum transferring operation transferring gypsum to landfills by trucks on paved roads.
- (The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

**Emission Limitations and Standards [326 IAC 2-7-5(1)]**

D.5.1 Prevention of Significant Deterioration (PSD) Minor Limits [326 IAC 2-2]

In order to render the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)) not applicable to the 2008 Modification permitted under SSM No. 165-22733-00001, issued on January 8, 2008, the Permittee shall comply with the following:

- (a) The total limestone received shall not exceed 509,000 tons per twelve (12) consecutive month period with compliance determined at the end of each month.
- (b) The PM/PM<sub>10</sub> emissions from the lime handling operations shall not exceed the emission limits listed in the table below:

Emission Point	Unit Description	PM Emission Limit (lbs/ton)	PM <sub>10</sub> Emission Limit (lbs/ton)
EP-L1	Railcar/Truck Unloading	2.50E-05	2.50E-05
EP-L2	Hoppers	7.50E-04	2.75E-04
EP-L2	Belt Feeders	7.50E-04	2.75E-04
EP-L3	Conveyor LH-1	1.50E-03	5.50E-04
EP-L4	Reclaim Hoppers	7.50E-04	2.75E-04
EP-L4	Belt Feeders	7.50E-04	2.75E-04
EP-L18abc	Conveyor LH-2	7.50E-04	2.75E-04
EP-L18abc	Conveyor LH-3	7.50E-04	2.75E-04
EP-L16	Day Bin Unit 1	3.00E-03	1.10E-03
EP-L17	Day Bin Unit 2	3.00E-03	1.10E-03

- (c) The emissions from the following units of the limestone handling system shall be controlled by the control method specified in the table below:

Emission Point	Unit	Control Method
EP-L1	Railcar/Truck Unloading Operation	Fog Dust Suppression
EP-L2	Hoppers Belt Feeders LHBF-1 and LHBF-2	Fog Dust Suppression
EP-L3	Conveyor LH-1	Telescoping Chute
EP-L4	Reclaim Hoppers Belt Feeders LHBF-3 and LHBF-4	Fog Dust Suppression
EP-L18a, b, c	Conveyors LH-2 and LH-3	Fog Dust Suppression



- (d) The total gypsum processed shall not exceed 900,528 tons per twelve (12) consecutive month period with compliance determined at the end of each month.
- (e) The PM/PM<sub>10</sub> emissions from the gypsum conveying system shall not exceed the emission limits listed in the table below:

Unit Description	PM Emission Limit (lbs/ton)	PM <sub>10</sub> Emission Limit (lbs/ton)
Gypsum Conveying System	0.00014	0.000046

- (f) The limestone and gypsum stockpiles shall be controlled by wet suppression. The suppressant shall be applied in a manner and at a frequency sufficient to ensure compliance with 326 IAC 2-2.

Compliance with these limits, shall limit the potential to emit of PM and PM<sub>10</sub> to less than 25 tons and 15 tons per twelve (12) consecutive month period, respectively, and shall render the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)) not applicable to the 2008 Modification permitted under SSM No. 165-22733-00001.

**D.5.2 Particulate Emission Limitations for Manufacturing Processes [326 IAC 6-3-2]**

- (a) Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes), particulate emissions from the following emission units at the limestone handling and storage system, and the gypsum conveying system shall not exceed the emission limits listed in the table below while operating at the maximum throughput rate:

Unit Description	Max. Throughput Rate (tons/hr)	Particulate Emission Limit (lbs/hr)
Railcar/Truck Unloading Operation	1,000	77.6
Each of the Hoppers	500	69.0
Each of the Belt Feeders (LHBF-1 and LHBF-2)	500	69.0
Each of the Reclaim Hoppers	200	58.5
Each of the Belt Feeders (LHBF-3 and LHBF-4)	200	58.5
Gypsum Conveying System	150	55.4

The limitations for these facilities were calculated using the following equations.

Interpolation and extrapolation of the data for the process weight rate in excess of sixty thousand (60,000) pounds per hour shall be accomplished by use of the equation:

$$E = 55.0 P^{0.11} - 40 \quad \text{where } E = \text{rate of emission in pounds per hour and } P = \text{process weight rate in tons per hour}$$

- (b) Pursuant to 326 IAC 6-3-2(e)(3), when the process weight exceeds 200 tons per hour, the maximum allowable emission may exceed that shown in this table, provided the concentration of particulate matter in the gas discharged to the atmosphere is less than 0.10 pounds per 1,000 pounds of gases.

**D.5.3 Preventive Maintenance Plan [326 IAC 2-7-5(13)]**

A Preventive Maintenance Plan (PMP) is required for this unit and its control device. Section B - Preventive Maintenance Plan contains the Permittee's obligations with regard to the preventive maintenance plan required by this condition.

## **Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)]**

### **D.5.4 Visible Emissions Notations**

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- (a) Visible emission notations of the stack exhausts from the conveyors (EP-L3, EP-L18a through c) of the limestone handling and storage system shall be performed once per week during normal daylight operations when transferring limestone. A trained employee shall record whether emissions are normal or abnormal.
- (b) For processes operated continuously, "normal" means those conditions prevailing, or expected to prevail, eighty percent (80%) of the time the process is in operation, not counting startup or shut down time.
- (c) In the case of batch or discontinuous operations, readings shall be taken during that part of the operation that would normally be expected to cause the greatest emissions.
- (d) A trained employee is an employee who has worked at the plant at least one (1) month and has been trained in the appearance and characteristics of normal visible emissions for that specific process.
- (e) If abnormal emissions are observed, the Permittee shall take reasonable response steps. Failure to take response steps, shall be considered a deviation of this permit. Section C – Response to Excursions or Exceedances contains the Permittee's obligations with regard to responding to the reasonable response steps required by this condition.

## **Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]**

### **D.5.5 Record Keeping Requirements**

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- (a) To document the compliance status with Condition D.5.1(a), the Permittee shall maintain monthly records of the weight of limestone processed.
- (b) To document the compliance status with Condition D.5.1(d), the Permittee shall maintain monthly records of the weight of gypsum processed.
- (c) To document the compliance status with Condition D.5.4 Visible Emissions Notations, the Permittee shall maintain records of the weekly visible emission notations of the transfer points, railcar unloading stations and all response steps taken and the outcome for each. The Permittee shall include in its records when a visible emission notation is not taken and the reason for the lack of visible emission notation (e.g., the process did not operate that day).
- (d) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

### **D.5.6 Reporting Requirements**

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A quarterly summary of the information to document compliance with Conditions D.5.1(a) and D.5.1(d) shall be submitted, using the reporting forms located at the end of this permit, or their equivalent, not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

## SECTION D.6 EMISSIONS UNIT OPERATION CONDITIONS

### Emissions Unit Description:

- (j) One (1) Auxiliary Boiler, identified as emission unit Aux, with a maximum heat input capacity of 72.76 MMBtu/hr fired with distillate oil and exhausting out one stack identified as stack Aux-1. The Auxiliary boiler was constructed before 1968.

[Under NESHAP 40 CFR 63, Subpart DDDDD, this unit is part of an affected source]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

### Emission Limitations and Standards [326 IAC 2-7-5(1)]

#### D.6.0 Limited Use Boiler Requirement [40 CFR Part 63.7500(c) and 63.7575, Subpart DDDDD]

In order to render auxiliary boiler, identified as Aux a limited use boiler pursuant to 40 CFR 63.7500(c), the Permittee shall comply with the following:

The fuel usage of the auxiliary boiler, identified as Aux shall not exceed 455.2697 Kilogallons of No. 2 fuel oil per twelve (12) consecutive month period, with compliance determined at the end of each month.

Compliance with this limit will make the boiler, identified as Aux a limited use boiler pursuant to 40 CFR 63.7500(c).

#### D.6.1 Reserve

#### D.6.2 Particulate Emission Limitations for Sources of Indirect Heating [326 IAC 6-2-3]

Pursuant to 326 IAC 6-2-3 (Particulate Emission Limitations for Sources of Indirect Heating: Emission limitations for facilities specified in 326 IAC 6-2-1(c), the PM emissions from the Auxiliary Boiler stack shall not exceed 0.234 pound per million Btu heat input (lbs/MMBtu).

#### D.6.3 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

A Preventive Maintenance Plan (PMP) is required for this unit and its control device. Section B - Preventive Maintenance Plan contains the Permittee's obligations with regard to the preventive maintenance plan required by this condition.

### Compliance Determination Requirements [326 IAC 2-7-5(1)]

#### D.6.4 Reserve

### Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)]

#### D.6.5 Visible Emissions Notations

- (a) Visible emission notations of the Auxiliary Boiler stack exhaust (Aux-1) shall be performed once per day during normal daylight operations. A trained employee shall record whether emissions are normal or abnormal.
- (b) For processes operated continuously, "normal" means those conditions prevailing, or expected to prevail, eighty percent (80%) of the time the process is in operation, not counting startup or shut down time.
- (c) In the case of batch or discontinuous operations, readings shall be taken during that part of the operation that would normally be expected to cause the greatest emissions.

- (d) A trained employee is an employee who has worked at the plant at least one (1) month and has been trained in the appearance and characteristics of normal visible emissions for that specific process.
- (e) If abnormal emissions are observed, the Permittee shall take reasonable response steps. Failure to take response steps, shall be considered a deviation from this permit. Section C – Response to Excursions or Exceedances contains the Permittee's obligations with regard to responding to the reasonable response steps required by this condition.

### **Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]**

#### **D.6.6 Record Keeping Requirement**

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- (a) To document the compliance status with Condition D.6.5, the Permittee shall maintain records of visible emission notations of the boiler stack (Aux-1) exhaust. The Permittee shall include in its records when a visible emission notation is not taken and the reason for the lack of visible emission notation, (e.g. the process did not operate that day).
- (b) To document the compliance status with Condition D.6.0, the Permittee shall maintain records of fuel usage for the days the boiler, identified as Aux is operating.
- (c) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

#### **D.6.7 Reporting Requirements**

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A quarterly report of the information to document the compliance status with Condition D.6.0 shall be submitted using the reporting forms located at the end of this permit, or their equivalent, not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

## SECTION D.7 EMISSIONS UNIT OPERATION CONDITIONS

### Emissions Unit Description:

- (k) One (1) Arsenic Mitigation System consisting of (1) 700 ton Limestone Storage Silo and (1) 300 ton Limestone Surge Bin, constructed in 2015. Limestone is pneumatically conveyed from delivery trucks to the Limestone Storage Silo and from the Limestone Storage Silo to the Limestone Surge Bin. Limestone in the Surge Bin is dropped on to the C-1 and C-2 coal conveyors. PM emissions generated during pneumatic conveying and transfer points to the C-1 and C-2 conveyor will be controlled by the bin vent filters. The Limestone Storage Silo and Limestone Surge Bin are identified as emissions points EP-01(LS) and EP-02(LS).
- (l) Two (2) Dry Sorbent Injection (DSI) Systems, one for each Unit. Each DSI system consists of one (1) Sorbent Storage Silo with a storage capacity of 120 tons, three (3) Silo Weight Feeders to regulate sorbent from the silos and a system to inject the sorbent material into the flue gas, constructed 2015. PM emissions generated during loading operations are controlled by a Bin Vent Filter located on the top of each silo and the weight feeders. The two (2) Sorbent Silos are identified as emission points EP-01(DSI), and EP-03(DSI). The weight feeders are identified as EP-05A(DSI), EP-05B(DSI), EP-06A(DSI) and EP-06B(DSI) with spares EP-05C(DSI) and EP-06C(DSI).
- (m) Two (2) Dry Ash Handling Systems, one for each Unit. The dry ash handling system consists of a pneumatic conveying system, five (5) baghouse separators, one (1) ash silo with a storage capacity of 3,500 and an ash unloading system, constructed in 2015.
- (i) Baghouse Separators - Fly ash from the ESP Ash Hoppers, Air Heater Ash Hoppers, Economizer Ash Hoppers and SCR Large Particle Screen, constructed in 2015. Ash Hopper will be pneumatically conveyed to one of five (5) baghouse separators. There will be two (2) baghouse separators for each unit. The dry fly ash is separated from the air stream in a baghouse separator. Each baghouse separator are identified as emissions points EP-01(DFA), EP-02(DFA), EP-03(DFA), and EP-04(DFA). The system is equipped with a spare exhaustor identified as emissions point EP-05(DFA).
- (ii) Ash Silos - Fly ash collected in the baghouse separators is dropped into a feeder and pneumatically conveyed to the ash silo, constructed in 2015. The ash silo is equipped with a bin vent filter to control particulate matter emissions from pneumatic conveying. The Ash Silo is identified as emission point EP-06(DFA).
- (iii) Ash Unloading Operation - Fly ash collected in the silos can be unloaded into trucks or pneumatically conveyed to the ash fixation process, constructed in 2015. Fly ash unloaded into trucks can be unloaded dry or wet. Fly ash unloaded dry is gravity feed to a chute and unloaded into enclosed trucks. The emissions generated from unloading the ash dry are vented back to the silo and controlled by the silo bin vent filter. Ash unloaded wet is feed into a pin mixer where the ash is mixed with water and unloaded into open trucks.
- (n) One (1) Ash Fixation Process consisting of a pneumatic conveying system, one (1) lime silo, conveyors, and two (2) pin mixers.
- (i) Lime Silo – Lime will be delivered by truck and will be pneumatically loaded into the silo. The storage capacity of the silo is 300 tons, constructed in 2015. The emissions generated by the pneumatic conveying will be controlled by a bin vent filter located on top of the lime silo. The Lime Silo is identified as emissions point EP-02(FIX).
- (ii) Conveyor and Transfer Points – Fly ash, Lime and Gypsum will be conveyed to one of two (2) pin mixers where this material will be mixed with water to make the fixated ash

constructed in 2015. The fixated ash will be unloaded to a storage pile, and then loaded into trucks using front end loaders.

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

**Emission Limitations and Standards [326 IAC 2-7-5(1)]**

**D.7.1 Prevention of Significant Deterioration (PSD) Minor Limits [326 IAC 2-2]**

In order to render the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)) not applicable to the 2012 Modification permitted under SSM No. 165-32045-00001, issued on September 5, 2012 and as modified under SSM No. 165-33709-00001, issued on November 27, 2013, the Permittee shall comply with the following:

- (a) Fly ash unloaded from the fly ash silo shall either be unloaded wet into open trucks with the ash having a moisture content of not less than 15% or unloaded dry into enclosed trucks using the telescoping chute to vent emissions back to the fly ash silo bin vent filter.
- (b) The PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the Activity on Storage Pile shall be controlled by maintaining the average moisture content of the fixated ash not less than 15% moisture content and applying water to the pile as need to prevent dusting.
- (c) The PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the limestone, dry sorbent, dry ash and ash fixation systems shall not exceed the emission limits listed in the table below:

Emission Point	Unit Description	PM Emission Limit (lbs/hr)	PM10 Emission Limit (lbs/hr)	PM2.5 Emission Limit (lbs/hr)
EP-01(LS)	Limestone Silo	0.094	0.094	0.094
EP-02(LS)	Limestone Surge Bin	0.097	0.097	0.097
EP-01(DSI)	Unit 1 DSI Silo #1	0.043	0.043	0.043
EP-03(DSI)	Unit 2 DSI Silo #1	0.043	0.043	0.043
EP-05A(DSI)	Sorbent Silo Weight Feeders	0.0086	0.0086	0.0086
EP-05B(DSI)	Sorbent Silo Weight Feeders			
EP-06A(DSI)	Sorbent Silo Weight Feeders	0.0086	0.0086	0.0086
EP-06B(DSI)	Sorbent Silo Weight Feeders			
EP-01(DFA)	Baghouse Separator 1A Exhauster	0.21	0.21	0.21
EP-02(DFA)	Baghouse Separator 1B Exhauster	0.21	0.21	0.21
EP-03(DFA)	Baghouse Separator 2A Exhauster	0.21	0.21	0.21
EP-04(DFA)	Baghouse Separator 2B Exhauster	0.21	0.21	0.21
EP-05(DFA)	Spare Baghouse Separator Exhauster	0.21	0.21	0.21
EP-06(DFA)	Ash Silo #1	0.21	0.21	0.21
EP-02(FIX)	Lime Silo	0.103	0.103	0.103

Compliance with these limits, shall limit the potential to emit of PM, PM<sub>10</sub>, and PM<sub>2.5</sub> to less than 25 tons per twelve (12) consecutive month period, PM<sub>10</sub> emissions are less than 15 tons per year, PM<sub>2.5</sub> emissions are less than 10 tons per year shall render the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)) not applicable to the 2012 Modification permitted under SSM No. 165-32045-00001 and as modified in 2013 under SSM No. 165-33709-00001, issued November 27, 2013.

**D.7.2 Particulate Emission Limitations for Manufacturing Processes [326 IAC 6-3-2]**

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- (a) Pursuant to 326 IAC 6-3-2, the allowable particulate matter (PM) from the (2) Sorbent Silos, (1) Lime Silo and (1) Limestone Silo shall not exceed 30.5 pounds per hour each when operating at a process weight rate of 20 tons per hour. The pound per hour limitation was calculated with the following equation:

$$E = 4.1 P^{0.67}$$

Where: E = rate of emission in pounds per hour and  
P = process weight rate in tons per hour

- (b) Pursuant to 326 IAC 6-3-2, the particulate matter (PM) from the (1) Limestone Surge Bin shall not exceed 40.0 pounds per hour when operating at a process weight rate of 30 tons per hour each. The pound per hour limitation was calculated with the following equation:

$$E = 4.1 P^{0.67}$$

Where: E = rate of emission in pounds per hour and  
P = process weight rate in tons per hour

- (c) Pursuant to 326 IAC 6-3-2, the particulate matter (PM) from (5) exhausters shall not exceed 45.4 pounds per hour each when operating at a process weight rate of 54.4 tons per hour. The pound per hour limitation was calculated with the following equation:

$$E = 55.0 P^{0.11} - 40$$

Where: E = rate of emission in pounds per hour and  
P = process weight rate in tons per hour

- (d) Pursuant to 326 IAC 6-3-2, the particulate matter (PM) from the ash silo shall not exceed 47.8 pounds per hour when operating at a process weight rate of 70 tons per hour. The pound per hour limitation was calculated with the following equation:

$$E = 55.0 P^{0.11} - 40$$

Where: E = rate of emission in pounds per hour and  
P = process weight rate in tons per hour

**D.7.3 Preventive Maintenance Plan [326 IAC 2-7-5(13)]**

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A Preventive Maintenance Plan (PMP) is required for this unit and its control device. Section B - Preventive Maintenance Plan contains the Permittee's obligations with regard to the preventive maintenance plan required by this condition.

**Compliance Determination Requirements [326 IAC 2-7-5(1)]**

**D.7.4 Particulate Control**

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- (a) In order to assure compliance with the particulate matter emissions limits specified in conditions D.7.1(c) and D.7.2 the filter separators, and silo bin vent filters shall in operation and controlling emissions whenever the equipment is in operation and venting to the control device.
- (b) In order to assure compliance with Condition D.7.1(a), the Permittee shall wet the ash when unloading into open trucks. If the weather conditions preclude the use of water, the Permittee shall use additional wet suppression. The Permittee shall perform moisture content analysis, prior to loading into open truck, on the ash to ensure it has a moisture

content of not less than 15%. Additional wetting of the ash should be applied if visible emissions are observed during the loading process.

**D.7.5 Testing Requirements [326 IAC 2-7-6(1), (6)][326 IAC 2-1.1-11]**

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In order to determine compliance with Condition D.7.1(c), the Permittee shall perform PM, PM<sub>10</sub> and PM<sub>2.5</sub> testing of two (2) of the five (5) separator/exhausters, identified as emissions point EP-01 (DFA), EP-02 (DFA), EP-03 (DFA), EP-04 (DFA) and EP-05 (DFA), using methods as approved by the Commissioner. This testing shall be at least once every 5 years from the date of the last valid compliance demonstration. The separator/exhauster tested shall be the unit in which the longest amount of time has elapsed since its previous test. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligations with regard to the performance testing required by this condition.

**Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)]**

**D.7.6 Visible Emissions Notations [40 CFR 64]**

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- (a) Visible emission notations of the stack exhausts for the (1) Limestone Silo (1) Limestone Surge Bin, (2) DSI Silos, and (1) Lime Silo shall be performed once per week during normal daylight operations when the equipment is in operation. A trained employee shall record whether emissions are normal or abnormal.
- (b) Visible emission notations of the stack for the five (5) baghouse separator exhausters, and ash silo shall be performed once per week during normal daylight operations when the equipment is in operation. A trained employee shall record whether emissions are normal or abnormal.
- (c) Visible emission notations of the fixated material storage pile shall be performed once per week during normal daylight operations when the equipment is in operation. A trained employee shall record whether emissions are normal or abnormal.
- (d) For processes operated continuously, "normal" means those conditions prevailing, or expected to prevail, eighty percent (80%) of the time the process is in operation, not counting startup or shut down time.
- (f) In the case of batch or discontinuous operations, readings shall be taken during that part of the operation that would normally be expected to cause the greatest emissions.
- (g) A trained employee is an employee who has worked at the plant at least one (1) month and has been trained in the appearance and characteristics of normal visible emissions for that specific process.
- (h) If abnormal emissions are observed, the Permittee shall take reasonable response steps. Observation of abnormal emissions that do not violate an applicable opacity limit is not a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit. Section C – Response to Excursions or Exceedances contains the Permittee's obligations with regard to responding to the reasonable response steps required by this condition.

**D.7.7 Reserved**

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**Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]**

**D.7.8 Record Keeping Requirements**

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- (a) To document the compliance status with Condition D.7.6(a), the Permittee shall maintain weekly records of the visible emission notations of the stack exhausts for the (1)



Limestone Silo, (1) Limestone Surge Bin, (2) DSI Silos and (1) Lime Silo. The Permittee shall include in its weekly record when a visible emission notation is not taken and the reason for the lack of a visible emission notation, (e.g. the process did not operate that week).

- (b) To document the compliance status with Condition D.7.6(b), the Permittee shall maintain weekly records of the visible emission notations of the stack exhaust for (5) Baghouse Filter Separators Exhausters, and Ash Silos when in operation. The Permittee shall include in its daily record when a visible emission notation is not taken and the reason for the lack of a visible emission notation, (e.g. the process did not operate that day).
- (c) To document the compliance status with Condition D.7.6(c), the Permittee shall maintain weekly records of the visible emission notations of the fixated material storage pile when in operation. The Permittee shall include in its weekly record when a visible emission notation is not taken and the reason for the lack of a visible emission notation, (e.g. the process did not operate that week).
- (d) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

## SECTION D.8 EMISSIONS UNIT OPERATION CONDITIONS

### Emissions Unit Description:

- (a) Degreasing operations that do not exceed one hundred forty-five (145) gallons per twelve months, except if subject to 326 IAC 20-6. [326 IAC 8-3-2] [326 IAC 8-3-8]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

### Emission Limitations and Standards [326 IAC 2-7-5(1)]

#### D.8.1 Cold Cleaner Degreaser Control Equipment and Operating Requirements (VOC) [326 IAC 8-3-2]

- (a) Pursuant to 326 IAC 8-3-2 (Cold Cleaner Degreaser Control Equipment and Operating Requirements), for cold cleaning degreasers without remote solvent reservoirs constructed after July 1, 1990:
- (1) Equip the degreaser with a cover.
  - (2) Equip the degreaser with a device for draining cleaned parts.
  - (3) Close the degreaser cover whenever parts are not being handled in the degreaser.
  - (4) Drain cleaned parts for at least fifteen (15) seconds or until dripping ceases.
  - (5) Provide a permanent, conspicuous label that lists the operating requirements in (a)(3), (a)(4), (a)(6), and (a)(7) of this condition.
  - (6) Store waste solvent only in closed containers.
  - (7) Prohibit the disposal or transfer of waste solvent in such a manner that could allow greater than twenty percent (20%) of the waste solvent (by weight) to evaporate into the atmosphere.
- (b) The Permittee shall ensure the following additional control equipment and operating requirements are met:
- (1) Equip the degreaser with one (1) of the following control devices if the solvent is heated to a temperature of greater than forty-eight and nine-tenths (48.9) degrees Celsius (one hundred twenty (120) degrees Fahrenheit):
    - (A) A freeboard that attains a freeboard ratio of seventy-five hundredths (0.75) or greater.
    - (B) A water cover when solvent used is insoluble in, and heavier than, water.
    - (C) A refrigerated chiller.
    - (D) Carbon adsorption.
    - (E) An alternative system of demonstrated equivalent or better control as those outlined in (b)(1)(A) through (D) of this condition that is approved by the department. An alternative system shall be submitted to the U.S. EPA as a SIP revision.

- (2) Ensure the degreaser cover is designed so that it can be easily operated with one (1) hand if the solvent is agitated or heated.
- (3) If used, solvent spray:
  - (A) must be a solid, fluid stream; and
  - (B) shall be applied at a pressure that does not cause excessive splashing.

**D.8.2 Material Requirements for Cold Cleaner Degreasers (VOC) [326 IAC 8-3-8]**

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Pursuant to 326 IAC 8-3-8 (Material Requirements for Cold Cleaner Degreasers), the Permittee shall not operate a cold cleaner degreaser with a solvent that has a VOC composite partial vapor pressure than exceeds one (1) millimeter of mercury (nineteen-thousandths (0.019) pound per square inch) measured at twenty (20) degrees Celsius (sixty-eight (68) degrees Fahrenheit).

**D.8.3 Preventive Maintenance Plan [326 IAC 2-7-5(13)]**

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A Preventive Maintenance Plan (PMP) is required for this unit and its control device. Section B - Preventive Maintenance Plan contains the Permittee's obligations with regard to the preventive maintenance plan required by this condition.

**Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]**

**D.8.4 Record Keeping Requirement**

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- (a) Pursuant to 326 IAC 8-3-8(c)(2), the following records shall be maintained for each purchase of cold cleaner degreaser solvent:
  - (1) The name and address of the solvent supplier.
  - (2) The date of purchase (or invoice/bill dates of contract servicer indicating service date).
  - (3) The type of solvent purchased.
  - (4) The total volume of the solvent purchased.
  - (5) The true vapor pressure of the solvent measured in millimeters of mercury at twenty (20) degrees Celsius (sixty-eight (68) degrees Fahrenheit).
- (b) Section C - General Record Keeping Requirements of this permit contains the Permittee's obligations with regard to the records required by this condition

## SECTION E.1

## NSPS

### Emissions Unit Description:

- (b) One (1) Diesel Fired Emergency Generator, identified as ENG-1 with maximum capacity of 156.9 HP (100 kW), CI ICE with a displacement 4.4 liters, Manufactured by Caterpillar Model Year 2007, Model D100-6, constructed in 2007, exhausting outside the building. This generator is located in the switch yard and is operated as backup for the black start diesel aux feed.

[This is an affected facility under 40 CFR 60, Subpart IIII]  
[This is an affected unit under 40 CFR 63, Subpart ZZZZ]

- (c) One (1) Diesel Fired Emergency Engine, identified as ENG-2, with maximum capacity of 713 Hp (450 kW), CI ICE with a displacement 15.2 liters, Manufactured by Caterpillar, Model Year 2007, Model C15DITA, constructed in 2007, exhausting outside the building. This engine is used to quench the flue gas if the scrubber should fail.

[This is an affected facility under 40 CFR 60, Subpart IIII]  
[This is an affected unit under 40 CFR 63, Subpart ZZZZ]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

### New Source Performance Standards (NSPS) Requirements [326 IAC 2-7-5(1)]

#### E.1.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]

- (a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart IIII.
- (b) Pursuant to 40 CFR 60.4, the Permittee shall submit all required notifications and reports to:

Indiana Department of Environmental Management  
Compliance and Enforcement Branch, Office of Air Quality  
100 North Senate Avenue  
MC 61-53 IGCN 1003  
Indianapolis, Indiana 46204-2251

#### E.1.2 Standard of Performance for Stationary Compression Ignition Internal Combustion Engines NSPS [326 IAC 12] [40 CFR Part 60, Subpart IIII]

The Permittee shall comply with the following provisions of 40 CFR Part 60, Subpart IIII (included as Attachment C to the operating permit), which are incorporated by reference as 326 IAC 12, for the emission unit(s) listed above:

- (1) 40 CFR 60.4200(a)(2)(i), (a)(4)
- (2) 40 CFR 60.4205(b)
- (3) 40 CFR 60.4207 (b)
- (4) 40 CFR 60.4208
- (5) 40 CFR 60.4209(a)
- (6) 40 CFR 60.4211(a), (c), (f)(1), (f)(2)(i), (f)(3), (g)(2)
- (7) 40 CFR 60.4212

- (8) 40 CFR 60.4214(b)
- (9) 40 CFR 60.4218
- (10) 40 CFR 60.4219
- (11) Table 5
- (12) Table 8

## SECTION E.2

## NSPS

### Emissions Unit Description:

- (h) One (1) limestone handling and storage system for the flue gas desulfurization system, constructed in 2006, with a maximum throughput rate of 1,000 tons per hour, consisting of the following:
- (4) One (1) conveyor, identified as LH-1 controlled by a telescopic chute, and exhausting to emission point EP-L3. Under NSPS, Subpart OOO, this unit is considered a belt conveyor.
  - (9) One (1) conveyor, identified as LH-2 with a maximum capacity of 400 tons per hour, controlled by fog dust suppression. The emissions exhaust out the general building vents, identified as emission point EP-L18a and EP-L18b. Under NSPS, Subpart OOO, this unit is considered a belt conveyor.
  - (10) One (1) reversible conveyor, identified as LH-3 with a maximum capacity of 400 tons per hour, controlled by fog dust suppression. The emissions exhaust out the general building vents, identified as emission points EP-L18a and EP-L18b. Under NSPS, Subpart OOO, this unit is considered a belt conveyor.
  - (11) Two (2) day bins each with a maximum throughput rate of 400 tons per hour. Each bin is equipped with a Baghouse to control particulate emissions. Filter F-L1 and F-L2 exhaust to EP-L16 and EP-L17, respectively. Under NSPS, Subpart OOO, these units are considered storage bins.
  - (12) Two (2) wet ball mills each with a maximum capacity of 51 tons of limestone slurry per hour. Under NSPS, Subpart OOO, these units are considered grinding mills.

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

### New Source Performance Standards (NSPS) Requirements [326 IAC 2-7-5(1)]

#### E.2.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]

- (a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart OOO.
- (b) Pursuant to 40 CFR 60.4, the Permittee shall submit all required notifications and reports to:

Indiana Department of Environmental Management  
Compliance and Enforcement Branch, Office of Air Quality  
100 North Senate Avenue  
MC 61-53 IGCN 1003  
Indianapolis, Indiana 46204-2251

E.2.2 Standard of Performance for Nonmetallic Mineral Processing Plants Requirements NSPS  
[326 IAC 12] [40 CFR Part 60, Subpart OOO]

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The Permittee shall comply with the following provisions of 40 CFR Part 60, Subpart OOO (included as Attachment C to the operating permit), which are incorporated by reference as 326 IAC 12, for the emission unit(s) listed above:

- (1) 40 CFR 60.670
- (2) 40 CFR 60.671
- (3) 40 CFR 60.672
- (4) 40 CFR 60.673
- (5) 40 CFR 60.675
- (6) 40 CFR 60.676
- (7) Table 1
- (8) Table 2
- (9) Table 3

**SECTION E.3**

**NESHAP**

**Emissions Unit Description:**

- (a) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 1, installed in 1967, using #2 fuel oil for startup, shutdown, and stabilization purposes, with a nominal heat input capacity of 4,802 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, a flue gas desulfurization (FGD) system for control of SO<sub>2</sub>, and exhausting to stack 1. Stack 1 has continuous emissions monitors (CEMs) for nitrogen oxides (NO<sub>x</sub>), sulfur dioxide (SO<sub>2</sub>), and particulate matter (PM). Boiler No. 1 was configured with a low NO<sub>x</sub> burner in 1993. Selective Catalytic Oxidation (SCR) to control NO<sub>x</sub>, and Dry Sorbent Injection System to Control SO<sub>3</sub> constructed in 2015. The Boiler is equipped with a PM CEMS, SO<sub>2</sub> CEMS, and NO<sub>x</sub> CEMS.

[Under NESHAP Subpart UUUUU, this unit is part of an affected source.]

- (b) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 2, installed in 1968, using #2 fuel oil for startup, shutdown, and stabilization purposes, with a nominal heat input capacity of 4,802 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, a flue gas desulfurization (FGD) system for control of SO<sub>2</sub>, and exhausting to stack 2. Stack 2 has continuous emissions monitors (CEMs) for nitrogen oxides (NO<sub>x</sub>), sulfur dioxide (SO<sub>2</sub>), and particulate matter (PM) and a continuous opacity monitor (COM). The COM will no longer be used for permit compliance purposes as of April 16, 2016 or when the PM CEM is installed, certified, and operating to measure PM pursuant to this permit. Boiler No. 2 was configured with a low NO<sub>x</sub> burner in 1993. Selective Catalytic Oxidation (SCR) to control NO<sub>x</sub>, and Dry Sorbent Injection System to Control SO<sub>3</sub>, installed by 2015.

[Under NESHAP Subpart UUUUU, this unit is part of an affected source.]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

**National Emission Standards for Hazardous Air Pollutants (NESHAP) Requirements  
[326 IAC 2-7-5(1)]**

**E.3.1 General Provisions Relating to National Emission Standards for Hazardous Air Pollutants under 40 CFR Part 63 [326 IAC 20-1] [40 CFR Part 63, Subpart A]**

- (a) Pursuant to 40 CFR 63.1 the Permittee shall comply with the provisions of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 20-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 63, Subpart UUUUU.
- (b) Pursuant to 40 CFR 63.10, the Permittee shall submit all required notifications and reports to:

Indiana Department of Environmental Management  
Compliance and Enforcement Branch, Office of Air Quality  
100 North Senate Avenue  
MC 61-53 IGCN 1003  
Indianapolis, Indiana 46204-2251



E.3.2 Coal- and Oil-Fired Electric Utility Steam Generating Units NESHAP [40 CFR Part 63, Subpart UUUUU]

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The Permittee shall comply with the following provisions of 40 CFR Part 63, Subpart UUUUU (included as Attachment E to the operating permit), for the emission unit(s) listed above:

- (1) 40 CFR 63.9981
- (2) 40 CFR 63.9982(a)(1)
- (3) 40 CFR 63.9982(d)
- (4) 40 CFR 63.9984(b)
- (5) 40 CFR 63.9984(f)
- (6) 40 CFR 63.9991(a)(1)
- (7) 40 CFR 63.9991(b)
- (8) 40 CFR 63.9991(c)
- (9) 40 CFR 63.10000(a)
- (10) 40 CFR 63.10000(b)
- (11) 40 CFR 63.10000(c)(1)(i)
- (12) 40 CFR 63.10000(c)(1)(iii)
- (13) 40 CFR 63.10000(c)(1)(iv)
- (14) 40 CFR 63.10000(c)(1)(v)
- (15) 40 CFR 63.10000(c)(1)(vi)
- (16) 40 CFR 63.10000(d) - (g)
- (17) 40 CFR 63.10000(i) - (l)
- (18) 40 CFR 63.10005(a)(1)
- (19) 40 CFR 63.10005(a)(2)(i)
- (20) 40 CFR 63.10005(a)(2)(ii)
- (21) 40 CFR 63.10005(b)
- (22) 40 CFR 63.10005(d)(1)
- (23) 40 CFR 63.10005(d)(3)
- (24) 40 CFR 63.10005(e)
- (25) 40 CFR 63.10005(f)
- (26) 40 CFR 63.10005(h)(1)(i)
- (27) 40 CFR 63.10005(h)(2)
- (28) 40 CFR 63.10005(j)
- (29) 40 CFR 63.10005(k)
- (30) 40 CFR 63.10006(b)(1)
- (31) 40 CFR 63.10006(c)
- (32) 40 CFR 63.10006(f) - (j)
- (33) 40 CFR 63.10007(a)(1)
- (34) 40 CFR 63.10007(a)(2)
- (35) 40 CFR 63.10007(b)
- (36) 40 CFR 63.10007(d) - (g)
- (37) 40 CFR 63.10009(a)(1)
- (38) 40 CFR 63.10009(a)(2)(i)
- (39) 40 CFR 63.10009(a)(2)(ii)
- (40) 40 CFR 63.10009(b) - (j)
- (41) 40 CFR 63.10010(a)(1)
- (42) 40 CFR 63.10010(b)
- (43) 40 CFR 63.10010(c)
- (44) 40 CFR 63.10010(d)
- (45) 40 CFR 63.10010(f)
- (46) 40 CFR 63.10010(g)
- (47) 40 CFR 63.10010(i)
- (48) 40 CFR 63.10010(l)
- (49) 40 CFR 63.10011
- (50) 40 CFR 63.10020
- (51) 40 CFR 63.10021(a)

- (52) 40 CFR 63.10021(b)
- (53) 40 CFR 63.10021(d)(1)
- (54) 40 CFR 63.10021(d)(2)
- (55) 40 CFR 63.10021(e) - (i)
- (56) 40 CFR 63.10022
- (57) 40 CFR 63.10030
- (58) 40 CFR 63.10031
- (59) 40 CFR 63.10032
- (60) 40 CFR 63.10033
- (61) 40 CFR 63.10041
- (62) 40 CFR 63.10042
- (63) Table 2 item 1
- (64) Table 3 items 1, 3, 4
- (65) Table 5 items 1, 4, 5
- (66) Table 8
- (67) Appendix A

**SECTION E.4**

**NESHAP**

**Emissions Unit Description:**

- (j) One (1) Auxiliary Boiler, identified as emission unit Aux, with a maximum heat input capacity of 72.76 MMBtu/hr fired with distillate oil and exhausting out one stack identified as stack Aux-1. The Auxiliary boiler was constructed before 1968.

[Under NESHAP 40 CFR 63, Subpart DDDDD, this unit is part of an affected source]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

**National Emission Standards for Hazardous Air Pollutants (NESHAP) Requirements  
[326 IAC 2-7-5(1)]**

**E.4.1 General Provisions Relating to National Emission Standards for Hazardous Air Pollutants under 40 CFR Part 63 [326 IAC 20-1] [40 CFR Part 63, Subpart A]**

- (a) Pursuant to 40 CFR 63.1 the Permittee shall comply with the provisions of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 20-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 63, Subpart DDDDD.
- (b) Pursuant to 40 CFR 63.10, the Permittee shall submit all required notifications and reports to:

Indiana Department of Environmental Management  
Compliance and Enforcement Branch, Office of Air Quality  
100 North Senate Avenue  
MC 61-53 IGCN 1003  
Indianapolis, Indiana 46204-2251

**E.4.2 National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial Commercial, and Institutional Boilers and Process Heaters NESHAP [40 CFR Part 63, Subpart DDDDD]**

The Permittee shall comply with the following provisions of 40 CFR Part 63, Subpart DDDDD (included as Attachment F to the operating permit), for the emission unit(s) listed above:

- (1) 40 CFR 63.7485
- (2) 40 CFR 63.7490(a)(1)
- (3) 40 CFR 63.7490(d)
- (4) 40 CFR 63.7499(o)
- (5) 40 CFR 63.7500(c)
- (6) 40 CFR 63.7500(f)
- (7) 40 CFR 63.7515(d)
- (8) 40 CFR 63.7550(b)
- (9) 40 CFR 63.7550(c)(1)
- (10) 40 CFR 63.7550(c)(5)(vi)
- (11) 40 CFR 63.7550(c)(5)(xvii)
- (12) 40 CFR 63.7550(h)(3)
- (13) 40 CFR 63.7555(a)(1)
- (14) 40 CFR 63.7560
- (15) 40 CFR 63.7575

**SECTION E.5**

**NESHAP**

**Emissions Unit Description:**

- (c) One (1) no. 2 fuel oil-fired generator, identified as Unit No. 3A, installed in 1972, with a nominal heat input capacity of 30 million Btu per hour (MMBtu/hr), using an oxidation catalyst installed in 2017 as control, and exhausting to stack 3A.

[This is an affected facility under 40 CFR 63, Subpart ZZZZ]

- (d) One (1) no. 2 fuel oil-fired generator, identified as Unit No. 3B, installed in 1972, with a nominal heat input capacity of 30 million Btu per hour (MMBtu/hr), using an oxidation catalyst installed in 2017 as control, and exhausting to stack 3B.

[This is an affected facility under 40 CFR 63, Subpart ZZZZ]

- (e) One (1) no. 2 fuel oil-fired generator, identified as Unit No. 3C, installed in 1972, with a nominal heat input capacity of 30 million Btu per hour (MMBtu/hr), using an oxidation catalyst installed in 2017 as control, and exhausting to stack 3C.

[This is an affected unit under 40 CFR 63, Subpart ZZZZ]

- (f) One (1) no. 2 fuel oil-fired generator, identified as Unit No. 3D, installed in, with a nominal heat input capacity of 30 million Btu per hour (MMBtu/hr), using an oxidation catalyst installed in 2017 as control, and exhausting to stack 3D.

[This is an affected unit under 40 CFR 63, Subpart ZZZZ]

- (b) One (1) Diesel Fired Emergency Generator, identified as ENG-01 with maximum capacity of 156.9 HP (100 kW), CI ICE with a displacement 4.4 liters, Manufactured by Caterpillar Model Year 2007, Model D100-6, constructed in 2007, exhausting outside the building. This generator is located in the switch yard and is operated as backup for the black start diesel aux feed.

[This is an affected facility under 40 CFR 60, Subpart IIII]

[This is an affected unit under 40 CFR 63, Subpart ZZZZ]

- (c) One (1) Diesel Fired Emergency Engine, identified as ENG-2, with maximum capacity of 713 Hp (450 kW), CI ICE with a displacement 15.2 liters, Manufactured by Caterpillar, Model Year 2007, Model C15DITA, constructed in 2007, exhausting outside the building. This engine is use to quench the fuel gas if the scrubber should fail.

[This is an affected facility under 40 CFR 60, Subpart IIII]

[This is an affected unit under 40 CFR 63, Subpart ZZZZ]

- (d) One (1) Emergency Fire Pump Engine, identified as ENG-03, with maximum capacity of 430 Hp (321 kW) CI, manufactured by Caterpillar, Model Year 2005, Model 3406, exhausting outside the building.

[This is an affected unit under 40 CFR 63, Subpart ZZZZ]

- (e) One (1) SI emergency engine, identified as ENG-04 with maximum capacity of 67 Hp (50 kW), manufactured by Power Solutions International, fired with LPG, model year 2018 exhausting outside the building. The engine is used provide backup power to a microwave tower during the loss of power.

[This is an affected facility under 40 CFR 60, Subpart JJJJ]  
[This is an affected unit under 40 CFR 63, Subpart ZZZZ]

- (f) One (1) SI propane emergency generator, identified as ENG-05, permitted in 2024, with a maximum capacity of 229 brake horsepower, using no controls, and exhausting to atmosphere.

[This is an affected facility under 40 CFR 60, Subpart JJJJ]  
[This is an affected unit under 40 CFR 63, Subpart ZZZZ]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

### **National Emission Standards for Hazardous Air Pollutants (NESHAP) Requirements [326 IAC 2-7-5(1)]**

#### **E.5.1 General Provisions Relating to National Emission Standards for Hazardous Air Pollutants under 40 CFR Part 63 [326 IAC 20-1] [40 CFR Part 63, Subpart A]**

- (a) Pursuant to 40 CFR 63.1 the Permittee shall comply with the provisions of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 20-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 63, Subpart ZZZZ.

- (b) Pursuant to 40 CFR 63.10, the Permittee shall submit all required notifications and reports to:

Indiana Department of Environmental Management  
Compliance and Enforcement Branch, Office of Air Quality  
100 North Senate Avenue  
MC 61-53 IGCN 1003  
Indianapolis, Indiana 46204-2251

#### **E.5.2 National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating internal Combustion Engines NESHAP [40 CFR Part 63, Subpart ZZZZ]**

The Permittee shall comply with the following provisions of 40 CFR Part 63, Subpart ZZZZ (included as Attachment D to the operating permit).

- (a) For Engines identified 3A-3D:
- (1) 40 CFR 63.6580
  - (2) 40 CFR 63.6585(a) and (b)
  - (3) 40 CFR 63.6590(a)(1)(i)(4)
  - (4) 40 CFR 63.6595(a)(1) and (c)
  - (5) 40 CFR 63.6600(d)
  - (6) 40 CFR 63.6604(a)
  - (7) 40 CFR 63.6605
  - (8) 40 CFR 63.6610(a)
  - (9) 40 CFR 63.6615
  - (10) 40 CFR 63.6620(a), (b)(4), (d), (e), and (i)
  - (11) 40 CFR 63.6625(b) and (g) (12) 40 CFR 63.6630(a), (b), and (c)
  - (13) 40 CFR 63.6635
  - (14) 40 CFR 63.6640(a) and (b)(15) 40 CFR 63.6645(a), (b), (g), and (h)

- (16) 40 CFR 63.6650(b), (c), (d), and (f)
  - (17) 40 CFR 63.6655(a), (b), and (d)
  - (18) 40 CFR 63.6660
  - (19) 40 CFR 63.6665
  - (20) 40 CFR 63.6670
  - (21) 40 CFR 63.6675
  - (22) Table 2c, item 5
  - (23) Table 3, item 4
  - (24) Table 4, Items 1 and 3
  - (25) Table 5, item 2
  - (26) Table 6, item 10
  - (27) Table 7, item 1
  - (28) Table 8
- (b) For Engine identified as ENG-01
- (1) 40 CFR 63.6580
  - (2) 40 CFR 63.6585
  - (3) 40 CFR 63.6590(a)(2)(ii), (c)(7)
  - (4) 40 CFR 63.6595(a)(4)
  - (5) 40 CFR 63.6640(f)(1), (2)(i), and (3)
  - (6) 40 CFR 63.6665
  - (7) 40 CFR 63.6670
  - (8) 40 CFR 63.6675
  - (9) Table 8
- (c) For Engine identified as ENG-02:
- (1) 40 CFR 63.6580
  - (2) 40 CFR 63.6585
  - (3) 40 CFR 63.6590(a)(2)(i), (b)(1)(i)
  - (4) 40 CFR 63.6595(a)(3), (c)
  - (5) 40 CFR 63.6640(f)(1), (f)(2)(i), (f)(3)
  - (6) 40 CFR 63.6645(f)
  - (7) 40 CFR 63.6665
  - (8) 40 CFR 63.6670
  - (9) 40 CFR 63.6675
  - (10) Table 8
- (d) For Engine identified as ENG-03
- (1) 40 CFR 63.6580
  - (2) 40 CFR 63.6585
  - (3) 40 CFR 63.6590(a)(1)(ii)
  - (4) 40 CFR 63.6595(a)(1), (c)
  - (5) 40 CFR 63.6602
  - (6) 40 CFR 63.6604(b)
  - (7) 40 CFR 63.6605
  - (8) 40 CFR 63.6625(e)(f)(h)(i)
  - (9) 40 CFR 63.6640(f)(1), (2)(i), (3)
  - (10) 40 CFR 63.6655(f)
  - (11) 40 CFR 63.6665
  - (12) 40 CFR 63.6670
  - (13) 40 CFR 63.6675
  - (14) Table 2c item 1
  - (15) Table 8
- (e) For Engine identified as ENG-04 and ENG-05
- (1) 40 CFR 63.6580

- (2) 40 CFR 63.6585
- (3) 40 CFR 63.6590(a)(2)(ii), (c)(6)
- (4) 40 CFR 63.6595(a)(5)
- (5) 40 CFR 63.6640(f)(1), (2)(i), (3)
- (6) 40 CFR 63.6665
- (7) 40 CFR 63.6670
- (8) 40 CFR 63.6675
- (9) Table 8

**SECTION E.6**

**NSPS**

**Emissions Unit Description:**

- (e) One (1) SI emergency engine, identified as ENG-04 with maximum capacity of 67 Hp (50 kW), manufactured by Power Solutions International, fired with LPG, model year 2018 exhausting outside the building. The engine is used provide backup power to a microwave tower during the loss of power.

[This is an affected facility under 40 CFR 60, Subpart JJJJ]

- (f) One (1) SI propane emergency generator, identified as ENG-05, permitted in 2024, with a maximum capacity of 229 brake horsepower, using no controls, and exhausting to atmosphere.

[This is an affected facility under 40 CFR 60, Subpart JJJJ]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

**New Source Performance Standards (NSPS) Requirements [326 IAC 2-7-5(1)]**

**E.6.1 General Provisions Relating to National Emission Standards for Hazardous Air Pollutants under 40 CFR Part 63 [326 IAC 20-1] [40 CFR Part 63, Subpart A]**

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- (a) Pursuant to 40 CFR 63.1 the Permittee shall comply with the provisions of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 20-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 63, Subpart JJJJ.

- (b) Pursuant to 40 CFR 63.10, the Permittee shall submit all required notifications and reports to:

Indiana Department of Environmental Management  
Compliance and Enforcement Branch, Office of Air Quality  
100 North Senate Avenue  
MC 61-53 IGCN 1003  
Indianapolis, Indiana 46204-2251

**E.6.2 Standard of Performance For Stationary Spark Ignition Internal Combustion Engines [40 CFR Part 60, Subpart JJJJ]**

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The Permittee shall comply with the following provisions of 40 CFR Part 60, Subpart JJJJ (included as Attachment G to the operating permit), for the emission unit(s) listed above:

- (1) 40 CFR 60.4230
- (2) 40 CFR 60.4233
- (3) 40 CFR 60.4237
- (4) 40 CFR 60.4243(a), (b)(1), (d), (g), (i)
- (5) 40 CFR 60.4245(a), (b)
- (6) 40 CFR 60.4246(a)
- (7) 40 CFR 60.4248
- (8) Table 3



**SECTION F**

**TITLE IV CONDITIONS**

**ORIS Code: 1001**

**Emissions Unit Description:**

(a) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 1, installed in 1967, using #2 fuel oil for startup, shutdown, and stabilization purposes, with a nominal heat input capacity of 4,802 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, a flue gas desulfurization (FGD) system for control of SO<sub>2</sub>, and exhausting to stack 1. Stack 1 has continuous emissions monitors (CEMs) for nitrogen oxides (NO<sub>x</sub>), sulfur dioxide (SO<sub>2</sub>), and particulate matter (PM). Boiler No. 1 was configured with a low NO<sub>x</sub> burner in 1993. Selective Catalytic Oxidation (SCR) to control NO<sub>x</sub>, and Dry Sorbent Injection System to Control SO<sub>3</sub> constructed in 2015. The Boiler is equipped with a PM CEMS, SO<sub>2</sub> CEMS, NO<sub>x</sub> CEMS and Hg CEMS.

[Under NESHAP Subpart UUUUU, this unit is part of an affected source.]

(b) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 2, installed in 1968, using #2 fuel oil for startup, shutdown, and stabilization purposes, with a nominal heat input capacity of 4,802 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, a flue gas desulfurization (FGD) system for control of SO<sub>2</sub>, and exhausting to stack 2. Stack 2 has continuous emissions monitors (CEMs) for nitrogen oxides (NO<sub>x</sub>), sulfur dioxide (SO<sub>2</sub>), and particulate matter (PM). Boiler No. 2 was configured with a low NO<sub>x</sub> burner in 1993. Selective Catalytic Oxidation (SCR) to control NO<sub>x</sub>, and Dry Sorbent Injection System to Control SO<sub>3</sub> constructed in 2015. The Boiler is equipped with a PM CEMS, SO<sub>2</sub> CEMS, NO<sub>x</sub> CEMS and Hg CEMS.

[Under NESHAP Subpart UUUUU, this unit is part of an affected source.]

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

**Acid Rain Program**

F.1 Acid Rain Permit [326 IAC 2-7-5(1)(C)][326 IAC 21][40 CFR 72 through 40 CFR 78]

Pursuant to 326 IAC 21 (Acid Deposition Control), the Permittee shall comply with all provisions of the Acid Rain permit issued for this source, and any other applicable requirements contained in 40 CFR 72 through 40 CFR 78.

F.2 Title IV Emissions Allowances [326 IAC 2-7-5(4)][326 IAC 21]

Emissions exceeding any allowances that the Permittee lawfully holds under the Title IV Acid Rain Program of the Clean Air Act are prohibited, subject to the following limitations:

- (a) No revision of this permit shall be required for increases in emissions that are authorized by allowances acquired under the Title IV Acid Rain Program, provided that such increases do not require a permit revision under any other applicable requirement.
- (b) No limit shall be placed on the number of allowances held by the Permittee. The Permittee may not use allowances as a defense to noncompliance with any other applicable requirement.
- (c) Any such allowance shall be accounted for according to the procedures established in regulations promulgated under Title IV of the Clean Air Act.

**SECTION G TR NO<sub>x</sub> Annual Trading Program, TR NO<sub>x</sub> Ozone Season Group 3 Trading Program, and TR SO<sub>2</sub> Group 1 Trading Program Requirements (40 CFR 97.406), (40 CFR 97.1006), (40 CFR 97.606)**

**ORIS Code: 1001**

**Emissions Unit Description:**

(a) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 1, installed in 1967, using #2 fuel oil for startup, shutdown, and stabilization purposes, with a nominal heat input capacity of 4,802 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, a flue gas desulfurization (FGD) system for control of SO<sub>2</sub>, and exhausting to stack 1. Stack 1 has continuous emissions monitors (CEMs) for nitrogen oxides (NO<sub>x</sub>), sulfur dioxide (SO<sub>2</sub>), and particulate matter (PM). Boiler No. 1 was configured with a low NO<sub>x</sub> burner in 1993. Selective Catalytic Oxidation (SCR) to control NO<sub>x</sub>, Dry Sorbent Injection System to Control SO<sub>3</sub> constructed in 2015. The Boiler is equipped with a PM CEMS, SO<sub>2</sub> CEMS, NO<sub>x</sub> CEMS and Hg CEMS.

[Under NESHAP Subpart UUUUU, this unit is part of an affected source.]

(b) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 2, installed in 1968, using #2 fuel oil for startup, shutdown, and stabilization purposes, with a nominal heat input capacity of 4,802 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, a flue gas desulfurization (FGD) system for control of SO<sub>2</sub>, and exhausting to stack 2. Stack 2 has continuous emissions monitors (CEMs) for nitrogen oxides (NO<sub>x</sub>), sulfur dioxide (SO<sub>2</sub>), and particulate matter (PM). Boiler No. 2 was configured with a low NO<sub>x</sub> burner in 1993. Selective Catalytic Oxidation (SCR) to control NO<sub>x</sub>, Dry Sorbent Injection System to Control SO<sub>3</sub> constructed in 2015. The Boiler is equipped with a PM CEMS, SO<sub>2</sub> CEMS, NO<sub>x</sub> CEMS and Hg CEMS.

[Under NESHAP Subpart UUUUU, this unit is part of an affected source.]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

**G.1 Designated Representative Requirements**

The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with the following:

- (1) 40 CFR 97.413 through 97.418;
- (2) 40 CFR 97.1013 through 97.1018; and
- (3) 40 CFR 97.613 through 97.618.

**G.2 Emissions Monitoring, Reporting, and Recordkeeping Requirements**

(a) The owners and operators, and the designated representative, of each TR NO<sub>x</sub> Annual source, TR NO<sub>x</sub> Ozone Season Group 3 source, and TR SO<sub>2</sub> Group 1 source, and each TR NO<sub>x</sub> Annual unit at the source, TR NO<sub>x</sub> Ozone Season Group 3 unit at the source, and TR SO<sub>2</sub> Group 1 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR 97.430, 40 CFR 97.1030, and 40 CFR 97.630 (general requirements, including installation, certification, and data accounting, compliance deadlines, reporting data, prohibitions, and long-term cold storage), 97.431, 97.1031, and 97.631 (initial monitoring system certification and recertification procedures), 97.432, 97.1032, and 97.632 (monitoring system out-of-control periods),

97.433, 97.1033, and 97.633 (notifications concerning monitoring), 97.434, 97.1034, and 97.634 (recordkeeping and reporting, including monitoring plans, certification applications, quarterly reports, and compliance certification), and 97.435, 97.1035, and 97.635 (petitions for alternatives to monitoring, recordkeeping, or reporting requirements).

- (b) The emissions data determined in accordance with 40 CFR 97.430 through 97.435 shall be used to calculate allocations of TR NO<sub>x</sub> Annual allowances under 40 CFR 97.411(a)(2) and (b) and 97.412 and to determine compliance with the TR NO<sub>x</sub> Annual emissions limitation and assurance provisions under Condition H.3 below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.430 through 97.435 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.
- (c) The emissions data determined in accordance with 40 CFR 97.1030 through 97.1035 shall be used to calculate allocations of TR NO<sub>x</sub> Ozone Season Group 3 allowances under 40 CFR 97.1011(a)(2) and (b) and 97.1012 and to determine compliance with the TR NO<sub>x</sub> Ozone Season Group 3 emissions limitation and assurance provisions under Condition H.4 below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.1030 through 97.1035 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.
- (d) The emissions data determined in accordance with 40 CFR 97.630 through 97.635 shall be used to calculate allocations of TR SO<sub>2</sub> Group 1 allowances under 40 CFR 97.611(a)(2) and (b) and 97.612 and to determine compliance with the TR SO<sub>2</sub> Group 1 emissions limitation and assurance provisions under Condition H.5 below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.630 through 97.635 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

### G.3 NO<sub>x</sub> Annual Emissions Requirements

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- (a) TR NO<sub>x</sub> Annual emissions limitation.
  - (1) As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR NO<sub>x</sub> Annual source and each TR NO<sub>x</sub> Annual unit at the source shall hold, in the source's compliance account, TR NO<sub>x</sub> Annual allowances available for deduction for such control period under 40 CFR 97.424(a) in an amount not less than the tons of total NO<sub>x</sub> emissions for such control period from all TR NO<sub>x</sub> Annual units at the source.
  - (2) If total NO<sub>x</sub> emissions during a control period in a given year from the TR NO<sub>x</sub> Annual units at a TR NO<sub>x</sub> Annual source are in excess of the TR NO<sub>x</sub> Annual emissions limitation set forth in Condition H.3(a)(1) above, then:
    - (A) The owners and operators of the source and each TR NO<sub>x</sub> Annual unit at the source shall hold the TR NO<sub>x</sub> Annual allowances required for deduction under 40 CFR 97.424(d); and
    - (B) The owners and operators of the source and each TR NO<sub>x</sub> Annual unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act,

and each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR Part 97, Subpart AAAAA and the Clean Air Act.

- (b) TR NO<sub>x</sub> Annual assurance provisions.
- (1) If total NO<sub>x</sub> emissions during a control period in a given year from all TR NO<sub>x</sub> Annual units at TR NO<sub>x</sub> Annual sources in the state exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such NO<sub>x</sub> emissions during such control period exceeds the common designated representative's assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) TR NO<sub>x</sub> Annual allowances available for deduction for such control period under 40 CFR 97.425(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.425(b), of multiplying— (A) The quotient of the amount by which the common designated representative's share of such NO<sub>x</sub> emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the state for such control period, by which each common designated representative's share of such NO<sub>x</sub> emissions exceeds the respective common designated representative's assurance level; and (B) The amount by which total NO<sub>x</sub> emissions from all TR NO<sub>x</sub> Annual units at TR NO<sub>x</sub> Annual sources in the state for such control period exceed the state assurance level.
  - (2) The owners and operators shall hold the TR NO<sub>x</sub> Annual allowances required under Condition H.3(b)(1) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.
  - (3) Total NO<sub>x</sub> emissions from all TR NO<sub>x</sub> Annual units at TR NO<sub>x</sub> Annual sources in the State during a control period in a given year exceed the state assurance level if such total NO<sub>x</sub> emissions exceed the sum, for such control period, of the state NO<sub>x</sub> Annual trading budget under 40 CFR 97.410(a) and the state's variability limit under 40 CFR 97.410(b).
  - (4) It shall not be a violation of 40 CFR Part 97, Subpart AAAAA or of the Clean Air Act if total NO<sub>x</sub> emissions from all TR NO<sub>x</sub> Annual units at TR NO<sub>x</sub> Annual sources in the State during a control period exceed the state assurance level or if a common designated representative's share of total NO<sub>x</sub> emissions from the TR NO<sub>x</sub> Annual units at TR NO<sub>x</sub> Annual sources in the state during a control period exceeds the common designated representative's assurance level.
  - (5) To the extent the owners and operators fail to hold TR NO<sub>x</sub> Annual allowances for a control period in a given year in accordance with Conditions H.3(b)(1) through (3) above,
    - (A) The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and
    - (B) Each TR NO<sub>x</sub> Annual allowance that the owners and operators fail to hold for such control period in accordance with Conditions H.3(b)(1) through (3) above and each day of such control period shall constitute a separate violation of 40 CFR Part 97, Subpart AAAAA and the Clean Air

Act.

- (c) Compliance periods.
  - (1) A TR NO<sub>x</sub> Annual unit shall be subject to the requirements under Condition H.3(a) above for the control period starting on the later of January 1, 2015, or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.430(b) and for each control period thereafter.
  - (2) A TR NO<sub>x</sub> Annual unit shall be subject to the requirements under Condition H.3(b) above for the control period starting on the later of January 1, 2017, or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.430(b) and for each control period thereafter.
- (d) Vintage of allowances held for compliance.
  - (1) A TR NO<sub>x</sub> Annual allowance held for compliance with the requirements under Condition H.3(a)(1) above for a control period in a given year must be a TR NO<sub>x</sub> Annual allowance that was allocated for such control period or a control period in a prior year.
  - (2) A TR NO<sub>x</sub> Annual allowance held for compliance with the requirements under Condition H.3(a)(2)(1) and (b)(1) through (3) above for a control period in a given year must be a TR NO<sub>x</sub> Annual allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.
- (e) Allowance Management System requirements. Each TR NO<sub>x</sub> Annual allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR Part 97, Subpart AAAAA.
- (f) Limited authorization. A TR NO<sub>x</sub> Annual allowance is a limited authorization to emit one ton of NO<sub>x</sub> during the control period in one year. Such authorization is limited in its use and duration as follows:
  - (1) Such authorization shall only be used in accordance with the TR NO<sub>x</sub> Annual Trading Program; and
  - (2) Notwithstanding any other provision of 40 CFR Part 97, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.
- (g) Property right. A TR NO<sub>x</sub> Annual allowance does not constitute a property right.

G.4 NO<sub>x</sub> Ozone Season Group 3 Requirements

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- (a) TR NO<sub>x</sub> Ozone Season Group 3 emissions limitation.
  - (1) As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR NO<sub>x</sub> Ozone Season Group 3 source and each TR NO<sub>x</sub> Ozone Season Group 3 unit at the source shall hold, in the source's compliance account, TR NO<sub>x</sub> Ozone Season Group 3 allowances available for deduction for such control period under 40 CFR 97.1024(a) in an amount not less than the tons of total NO<sub>x</sub> emissions for such control period from all TR NO<sub>x</sub> Ozone Season Group 3 units at the source.

- (2) If total NO<sub>x</sub> emissions during a control period in a given year from the TR NO<sub>x</sub> Ozone Season Group 3 units at a TR NO<sub>x</sub> Ozone Season Group 3 source are in excess of the TR NO<sub>x</sub> Ozone Season Group 3 emissions limitation set forth in Condition H.4(a)(1) above, then:
  - (A) The owners and operators of the source and each TR NO<sub>x</sub> Ozone Season Group 3 unit at the source shall hold the TR NO<sub>x</sub> Ozone Season Group 3 allowances required for deduction under 40 CFR 97.1024(d); and
  - (B) The owners and operators of the source and each TR NO<sub>x</sub> Ozone Season Group 3 unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR Part 97, Subpart GGGGG and the Clean Air Act.
- (b) TR NO<sub>x</sub> Ozone Season Group 3 assurance provisions.
  - (1) If total NO<sub>x</sub> emissions during a control period in a given year from all TR NO<sub>x</sub> Ozone Season Group 3 units at TR NO<sub>x</sub> Ozone Season Group 3 sources in the state exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such NO<sub>x</sub> emissions during such control period exceeds the common designated representative's assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) TR NO<sub>x</sub> Ozone Season Group 3 allowances available for deduction for such control period under 40 CFR 97.1025(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.1025(b), of multiplying:
    - (A) The quotient of the amount by which the common designated representative's share of such NO<sub>x</sub> emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the state for such control period, by which each common designated representative's share of such NO<sub>x</sub> emissions exceeds the respective common designated representative's assurance level; and
    - (B) The amount by which total NO<sub>x</sub> emissions from all TR NO<sub>x</sub> Ozone Season Group 3 units at TR NO<sub>x</sub> Ozone Season Group 3 sources in the state for such control period exceed the state assurance level.
  - (2) The owners and operators shall hold the TR NO<sub>x</sub> Ozone Season Group 3 allowances required under Condition H.4(b)(1) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.
  - (3) Total NO<sub>x</sub> emissions from all TR NO<sub>x</sub> Ozone Season Group 3 units at TR NO<sub>x</sub> Ozone Season Group 3 sources in the state during a control period in a given year exceed the state assurance level if such total NO<sub>x</sub> emissions exceed the

sum, for such control period, of the State NO<sub>x</sub> Ozone Season Group 3 trading budget under 40 CFR 97.1010(a) and the state's variability limit under 40 CFR 97.1010(b).

- (4) It shall not be a violation of 40 CFR part 97, subpart GGGGG or of the Clean Air Act if total NO<sub>x</sub> emissions from all TR NO<sub>x</sub> Ozone Season Group 3 units at TR NO<sub>x</sub> Ozone Season Group 3 sources in the state during a control period exceed the state assurance level or if a common designated representative's share of total NO<sub>x</sub> emissions from the TR NO<sub>x</sub> Ozone Season Group 3 units at TR NO<sub>x</sub> Ozone Season Group 3 sources in the state during a control period exceeds the common designated representative's assurance level.
  - (5) To the extent the owners and operators fail to hold TR NO<sub>x</sub> Ozone Season Group 3 allowances for a control period in a given year in accordance with Conditions H.4(b)(1) through (3) above,
    - (A) The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and
    - (B) Each TR NO<sub>x</sub> Ozone Season Group 3 allowance that the owners and operators fail to hold for such control period in accordance with Conditions H.4(b)(1) through (3) above and each day of such control period shall constitute a separate violation of 40 CFR Part 97, Subpart GGGGG and the Clean Air Act.
- (c) Compliance Periods.
- (1) A TR NO<sub>x</sub> Ozone Season unit shall be subject to the requirements under Condition H.4(a) above for the control period starting on the later of May 1, 2015, or the deadline for meeting the unit's monitor certificate requirements under 40 CFR 97.1030(b) and for each control period thereafter.
  - (2) A TR NO<sub>x</sub> Ozone Season Group 3 unit shall be subject to the requirements under Condition H.4(b) above for the control period starting on the later of May 1, 2017, or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.1030(b) and for each control period thereafter.
- (d) Vintage of allowances held for compliance.
- (1) A TR NO<sub>x</sub> Ozone Season Group 3 allowance held for compliance with the requirements under Condition H.4(a)(1) above for a control period in a given year must be a TR NO<sub>x</sub> Ozone Season Group 3 Allowance that was allocated for such control period or a control period in a prior year.
  - (2) A TR NO<sub>x</sub> Ozone Season Group 3 allowance held for compliance with the requirements under Conditions H.4(a)(2)(A) and (b)(1) through (3) above for a control period in a given year must be a TR NO<sub>x</sub> Ozone Season Group 3 allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.
- (e) Allowances Management System Requirements.
- (1) Each TR NO<sub>x</sub> Ozone Season Group 3 allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR Part 97, Subpart GGGGG.

- (f) Limited Authorization.
  - (1) A TR NO<sub>x</sub> Ozone Season Group 3 allowance is a limited authorization to emit one ton of NO<sub>x</sub> during the control period in one year. Such authorization is limited in its use and duration as follows:
    - (A) Such authorization shall only be used in accordance with the TR NO<sub>x</sub> Ozone Season Group 3 Trading Program; and
    - (B) Notwithstanding any other provision of 40 CFR Part 97, Subpart GGGGG, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.
- (g) Property Right.
  - (1) A TR NO<sub>x</sub> Ozone Season Group 3 allowance does not constitute a property right.

#### G.5 SO<sub>2</sub> Emissions Requirements

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- (a) TR SO<sub>2</sub> Group 1 emissions limitation.
  - (1) As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR SO<sub>2</sub> Group 1 source and each TR SO<sub>2</sub> Group 1 unit at the source shall hold, in the source's compliance account, TR SO<sub>2</sub> Group 1 allowances available for deduction for such control period under 40 CFR 97.624(a) in an amount not less than the tons of total SO<sub>2</sub> emissions for such control period from all TR SO<sub>2</sub> Group 1 units at the source.
  - (2) If total SO<sub>2</sub> emissions during a control period in a given year from the TR SO<sub>2</sub> Group 1 units at a TR SO<sub>2</sub> Group 1 source are in excess of the TR SO<sub>2</sub> Group 1 emissions limitation set forth in Condition H.5(a)(1) above, then:
    - (A) The owners and operators of the source and each TR SO<sub>2</sub> Group 1 unit at the source shall hold the TR SO<sub>2</sub> Group 1 allowances required for deduction under 40 CFR 97.624(d); and
    - (B) The owners and operators of the source and each TR SO<sub>2</sub> Group 1 unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation 40 CFR Part 97, Subpart CCCCC and the Clean Air Act.
- (b) TR SO<sub>2</sub> Group 1 assurance provisions
  - (1) If total SO<sub>2</sub> emissions during a control period in a given year from all TR SO<sub>2</sub> Group 1 units at TR SO<sub>2</sub> Group 1 sources in the state exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such SO<sub>2</sub> emissions during such control period exceeds the common designated representative's assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) TR SO<sub>2</sub> Group 1 allowances available for deduction



for such control period under 40 CFR 97.625(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.625(b), of multiplying—

- (2) The quotient of the amount by which the common designated representative's share of such SO<sub>2</sub> emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the state for such control period, by which each common designated representative's share of such SO<sub>2</sub> emissions exceeds the respective common designated representative's assurance level; and
  - (3) The amount by which total SO<sub>2</sub> emissions from all TR SO<sub>2</sub> Group 1 units at TR SO<sub>2</sub> Group 1 sources in the state for such control period exceed the state assurance level.
  - (4) The owners and operators shall hold the TR SO<sub>2</sub> Group 1 allowances required under Condition H.5(b)(1) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.
  - (5) Total SO<sub>2</sub> emissions from all TR SO<sub>2</sub> Group 1 units at TR SO<sub>2</sub> Group 1 sources in the state during a control period in a given year exceed the state assurance level if such total SO<sub>2</sub> emissions exceed the sum, for such control period, of the state SO<sub>2</sub> Group 1 trading budget under 40 CFR 97.610(a) and the state's variability limit under 40 CFR 97.610(b).
  - (6) It shall not be a violation of 40 CFR part 97, subpart CCCCC or of the Clean Air Act if total SO<sub>2</sub> emissions from all TR SO<sub>2</sub> Group 1 units at TR SO<sub>2</sub> Group 1 sources in the state during a control period exceed the state assurance level or if a common designated representative's share of total SO<sub>2</sub> emissions from the TR SO<sub>2</sub> Group 1 units at TR SO<sub>2</sub> Group 1 sources in the state during a control period exceeds the common designated representative's assurance level.
  - (7) To the extent the owners and operators fail to hold TR SO<sub>2</sub> Group 1 allowances for a control period in a given year in accordance with Conditions H.5(b)(1) through (3) above,
    - (A) The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and
    - (B) Each TR SO<sub>2</sub> Group 1 allowance that the owners and operators fail to hold for such control period in accordance with Conditions H.5(b)(1) through (3) above and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart CCCCC and the Clean Air Act.
- (c) Compliance periods.
- (1) A TR SO<sub>2</sub> Group 1 unit shall be subject to the requirements under Condition H.5(a) above for the control period starting on the later of January 1, 2015, or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.630(b) and for each control period thereafter.
  - (2) A TR SO<sub>2</sub> Group 1 unit shall be subject to the requirements under Condition H.5(b) above for the control period starting on the later of January 1, 2017, or the

deadline for meeting the unit's monitor certification requirements under 40 CFR 97.630(b) and for each control period thereafter.

- (d) Vintage of allowances held for compliance.
  - (1) A TR SO<sub>2</sub> Group 1 allowance held for compliance with the requirements under Condition H.5(a)(1) above for a control period in a given year must be a TR SO<sub>2</sub> Group 1 allowance that was allocated for such control period or a control period in a prior year.
  - (2) A TR SO<sub>2</sub> Group 1 allowance held for compliance with the requirements under Condition H.5(a)(2)(A) and (b)(1) through (3) above for a control period in a given year must be a TR SO<sub>2</sub> Group 1 allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.
- (e) Allowance Management System requirements. Each TR SO<sub>2</sub> Group 1 allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR Part 97, Subpart CCCCC.
- (f) Limited authorization. A TR SO<sub>2</sub> Group 1 allowance is a limited authorization to emit one ton of SO<sub>2</sub> during the control period in one year. Such authorization is limited in its use and duration as follows:
  - (1) Such authorization shall only be used in accordance with the TR SO<sub>2</sub> Group 1 Trading Program; and
  - (2) Notwithstanding any other provision of 40 CFR Part 97, Subpart CCCCC, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.
- (g) Property right. A TR SO<sub>2</sub> Group 1 allowance does not constitute a property right.

#### G.6 Title V Permit Revision Requirements

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- (a) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of TR NO<sub>x</sub> Annual allowances in accordance with 40 CFR Part 97, Subpart AAAAA, TR NO<sub>x</sub> Ozone Season allowances in accordance with 40 CFR Part 97, Subpart GGGGG, and TR SO<sub>2</sub> Group 1 allowances in accordance with 40 CFR Part 97, Subpart CCCCC.
- (b) This permit incorporates the TR emissions monitoring, recordkeeping and reporting requirements pursuant to 40 CFR 97.430 through 97.435, 40 CFR 97.1030 through 97.1035, and 40 CFR 97.630 through 97.635, and the requirements for a continuous emission monitoring system (pursuant to 40 CFR part 75, subparts B and H), an excepted monitoring system (pursuant to 40 CFR part 75, appendices D and E), a low mass emissions excepted monitoring methodology (pursuant to 40 CFR 75.19), and an alternative monitoring system (pursuant to 40 CFR part 75, subpart E). Therefore, the Description of TR Monitoring Provisions table for units identified in this permit may be added to, or changed, in this title V permit using minor permit modification procedures in accordance with 40 CFR 97.406(d)(2), 40 CFR 97.1006(d)(2), and 40 CFR 97.606(d)(2) and 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B).

#### G.7 Additional recordkeeping and reporting requirements

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- (a) Unless otherwise provided, the owners and operators of each TR NO<sub>x</sub> Annual source and each TR NO<sub>x</sub> Annual unit, TR NO<sub>x</sub> Ozone Season Group 3 source and each TR NO<sub>x</sub>

Ozone Season Group 3 unit, and TR SO<sub>2</sub> Group 1 source and each TR SO<sub>2</sub> Group 1 unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

- (1) The certificate of representation under 40 CFR 97.416, 40 CFR 97.1016, and 40 CFR 97.616 for the designated representative for the source and each TR NO<sub>x</sub> Annual unit, TR NO<sub>x</sub> Ozone Season Group 3 unit, and TR SO<sub>2</sub> Group 1 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under 40 CFR 97.416, 40 CFR 97.1016, and 40 CFR 97.616 changing the designated representative.
  - (2) All emissions monitoring information, in accordance with 40 CFR Part 97, Subpart AAAAA, 40 CFR Part 97, Subpart GGGGG, and 40 CFR Part 97, Subpart CCCCC.
  - (3) Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the TR NO<sub>x</sub> Annual Trading Program, TR NO<sub>x</sub> Ozone Season Group 3 Trading Program, and TR SO<sub>2</sub> Group 1 Trading Program.
- (b) The designated representative of a TR NO<sub>x</sub> Annual source and each TR NO<sub>x</sub> Annual unit, a TR NO<sub>x</sub> Ozone Season Group 3 source and each TR NO<sub>x</sub> Ozone Season Group 3 unit, and a TR SO<sub>2</sub> Group 1 source and each TR SO<sub>2</sub> Group 1 unit at the source shall make all submissions required under the TR NO<sub>x</sub> Annual Trading Program, TR NO<sub>x</sub> Ozone Season Group 3 Trading Program, and TR SO<sub>2</sub> Group 1 Trading Program, except as provided in 40 CFR 97.418, 40 CFR 97.1018, and 40 CFR 97.618. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in 40 CFR Parts 70 and 71.

#### G.8 Liability

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- (a) Any provision of the TR NO<sub>x</sub> Annual Trading Program that applies to a TR NO<sub>x</sub> Annual source or the designated representative of a TR NO<sub>x</sub> Annual source shall also apply to the owners and operators of such source and of the TR NO<sub>x</sub> Annual units at the source.
- (b) Any provision of the TR NO<sub>x</sub> Annual Trading Program that applies to a TR NO<sub>x</sub> Annual unit or the designated representative of a TR NO<sub>x</sub> Annual unit shall also apply to the owners and operators of such unit.
- (c) Any provision of the TR NO<sub>x</sub> Ozone Season Group 3 Trading Program that applies to a TR NO<sub>x</sub> Ozone Season Group 3 source or the designated representative of a TR NO<sub>x</sub> Ozone Season Group 3 source shall also apply to the owners and operators of such source and of the TR NO<sub>x</sub> Ozone Season Group 3 units at the source.
- (d) Any provision of the TR NO<sub>x</sub> Ozone Season Group 3 Trading Program that applies to a TR NO<sub>x</sub> Ozone Season Group 3 unit or the designated representative of a TR NO<sub>x</sub> Ozone Season Group 3 unit shall also apply to the owners and operators of such unit.
- (e) Any provision of the TR SO<sub>2</sub> Group 1 Trading Program that applies to a TR SO<sub>2</sub> Group 1 source or the designated representative of a TR SO<sub>2</sub> Group 1 source shall also apply to the owners and operators of such source and of the TR SO<sub>2</sub> Group 1 units at the source.

- (f) Any provision of the TR SO<sub>2</sub> Group 1 Trading Program that applies to a TR SO<sub>2</sub> Group 1 unit or the designated representative of a TR SO<sub>2</sub> Group 1 unit shall also apply to the owners and operators of such unit.

**G.9 Effect on Other Authorities**

No provision of the TR NO<sub>x</sub> Annual Trading Program or exemption under 40 CFR 97.405, TR NO<sub>x</sub> Ozone Season Group 3 Trading Program or exemption under 40 CFR 97.1005, and TR SO<sub>2</sub> Group 1 Trading Program or exemption under 40 CFR 97.605 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a TR NO<sub>x</sub> Annual source or TR NO<sub>x</sub> Annual unit, TR NO<sub>x</sub> Ozone Season Group 3 source or TR NO<sub>x</sub> Ozone Season Group 3 unit, and TR SO<sub>2</sub> Group 1 source or TR SO<sub>2</sub> Group 1 unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act.

**G.10 Description of TR Monitoring Provisions**

The TR subject unit(s) and the unit-specific monitoring provisions at this source are identified in the following table(s). These units are subject to the requirements for the TR NO<sub>x</sub> Annual Trading Program, TR NO<sub>x</sub> Ozone Season Trading Program, and TR SO<sub>2</sub> Group 1 Trading Program.

Parameter	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR, Part 75, Subpart B (for SO <sub>2</sub> monitoring) & 40 CFR, Part 75, Subpart H (for NO <sub>x</sub> Monitoring)	Excepted monitoring system requirements for gas-fired & oil-fired units pursuant to 40 CFR, Part 75, Appendix D	Excepted monitoring system requirements for gas-fired & oil-fired peaking units pursuant to 40 CFR, Part 75, Appendix E	Low Mass Emissions excepted monitoring (LME) requirements for gas-fired & oil-fired units pursuant to 40 CFR 75.19	EPA-approved alternative monitoring system requirements pursuant to 40 CFR, Part 75, Subpart E
SO <sub>2</sub>	X	--	--	--	--
NO <sub>x</sub>	X	--	--	--	--
Heat Input	X	--	--	--	--

- (a) The above description of the monitoring used by a unit does not change, create an exemption from, or otherwise affect the monitoring, recordkeeping, and reporting requirements applicable to the unit under 40 CFR 97.430 through 97.435 (TR NO<sub>x</sub> Annual Trading Program), 97.1030 through 97.1035 (TR NO<sub>x</sub> Ozone Season Group 3 Trading Program), and 97.630 through 97.635 (TR SO<sub>2</sub> Group 1 Trading Program), as applicable. The monitoring, recordkeeping and reporting requirements applicable to each unit are included below in the standard conditions for the applicable TR trading programs.
- (b) Owners and operators must submit to the Administrator a monitoring plan for each unit in accordance with 40 CFR 75.53, 75.62 and 75.73, as applicable. The monitoring plan for each unit is available at the EPA's website at <http://www.epa.gov/airmarkets/emissions/monitoringplans.html>.
- (c) Owners and operators that want to use an alternative monitoring system must submit to the Administrator a petition requesting approval of the alternative monitoring system in accordance with 40 CFR part 75, subpart E and 40 CFR 75.66 and 97.435 (TR NO<sub>x</sub> Annual Trading Program), 97.1035 (TR NO<sub>x</sub> Ozone Season Group 3 Trading Program), and 97.635 (TR SO<sub>2</sub> Group 1 Trading Program), as applicable. The Administrator's response approving or disapproving any petition for an alternative monitoring system is available on the EPA's website at <http://www.epa.gov/airmarkets/emissions/petitions.html>.

- (d) Owners and operators that want to use an alternative to any monitoring, recordkeeping, or reporting requirement under 40 CFR 97.430 through 97.434 (TR NO<sub>x</sub> Annual Trading Program), 97.1030 through 97.1034 (TR NO<sub>x</sub> Ozone Season Group 3 Trading Program), and 97.630 through 97.634 (TR SO<sub>2</sub> Group 1 Trading Program), as applicable, must submit to the Administrator a petition requesting approval of the alternative in accordance with 40 CFR 75.66 and 97.435 (TR NO<sub>x</sub> Annual Trading Program), 97.1035 (TR NO<sub>x</sub> Ozone Season Group 3 Trading Program), and 97.635 (TR SO<sub>2</sub> Group 1 Trading Program), as applicable. The Administrator's response approving or disapproving any petition for an alternative to a monitoring, recordkeeping, or reporting requirement is available on EPA's website at <http://www.epa.gov/airmarkets/emissions/petitions.html>.
- (e) The descriptions of monitoring applicable to the unit included above meet the requirement of 40 CFR 97.430 through 97.434 (TR NO<sub>x</sub> Annual Trading Program), 97.1030 through 97.1034 (TR NO<sub>x</sub> Ozone Season Group 3 Trading Program), and 97.630 through 97.634 (TR SO<sub>2</sub> Group 1 Trading Program), as applicable, and therefore minor permit modification procedures, in accordance with 40 CFR 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B), may be used to add to or change this unit's monitoring system description.

**INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT  
OFFICE OF AIR QUALITY  
COMPLIANCE AND ENFORCEMENT BRANCH  
PART 70 OPERATING PERMIT  
CERTIFICATION**

Source Name: Duke Energy Indiana, LLC - Cayuga Generating Station  
Source Address: 3300 N SR 63, Cayuga, Indiana 47928  
Part 70 Permit No.: T165-47094-00001

**This certification shall be included when submitting monitoring, testing reports/results or other documents as required by this permit.**

Please check what document is being certified:

- Annual Compliance Certification Letter
- Test Result (specify) \_\_\_\_\_
- Report (specify) \_\_\_\_\_
- Notification (specify) \_\_\_\_\_
- Affidavit (specify) \_\_\_\_\_
- Other (specify) \_\_\_\_\_

I certify that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

Signature:

Printed Name:

Title/Position:

Phone:

Date:

**INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT  
OFFICE OF AIR QUALITY  
COMPLIANCE AND ENFORCEMENT BRANCH  
100 North Senate Avenue  
MC 61-53 IGCN 1003  
Indianapolis, Indiana 46204-2251  
Phone: (317) 233-0178  
Fax: (317) 233-6865**

**PART 70 OPERATING PERMIT  
EMERGENCY OCCURRENCE REPORT**

Source Name: Duke Energy Indiana, LLC - Cayuga Generating Station  
Source Address: 3300 N SR 63, Cayuga, Indiana 47928  
Part 70 Permit No.: T165-47094-00001

**This form consists of 2 pages**

**Page 1 of 2**

<input type="checkbox"/> This is an emergency as defined in 326 IAC 2-7-1(12) <ul style="list-style-type: none"><li>• The Permittee must notify the Office of Air Quality (OAQ), within four (4) daytime business hours (1-800-451-6027 or 317-233-0178, ask for Compliance Section); and</li><li>• The Permittee must submit notice in writing or by facsimile within two (2) working days (Facsimile Number: 317-233-6865) and follow the other requirements of 326 IAC 2-7-16.</li></ul>
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If any of the following are not applicable, mark N/A

Facility/Equipment/Operation:
Control Equipment:
Permit Condition or Operation Limitation in Permit:
Description of the Emergency:
Describe the cause of the Emergency:

If any of the following are not applicable, mark N/A

**Page 2 of 2**

Date/Time Emergency started:		
Date/Time Emergency was corrected:		
Was the facility being properly operated at the time of the emergency?	Y	N
Type of Pollutants Emitted: TSP, PM-10, SO <sub>2</sub> , VOC, NO <sub>x</sub> , CO, Pb, other:		
Estimated amount of pollutant(s) emitted during emergency:		
Describe the steps taken to mitigate the problem:		
Describe the corrective actions/response steps taken:		
Describe the measures taken to minimize emissions:		
If applicable, describe the reasons why continued operation of the facilities are necessary to prevent imminent injury to persons, severe damage to equipment, substantial loss of capital investment, or loss of product or raw materials of substantial economic value:		

Form Completed by: \_\_\_\_\_

Title / Position: \_\_\_\_\_

Date: \_\_\_\_\_

Phone: \_\_\_\_\_



**INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT  
OFFICE OF AIR QUALITY  
COMPLIANCE AND ENFORCEMENT BRANCH**

**Part 70 Quarterly Report**

Source Name: Duke Energy Indiana, LLC - Cayuga Generating Station  
Source Address: 3300 N SR 63, Cayuga, Indiana 47928  
Part 70 Permit No.: T165-47094-00001  
Facility: Limestone Handling System  
Parameter: Amount of limestone received  
Limit: Less than 509,000 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

QUARTER: \_\_\_\_\_ YEAR: \_\_\_\_\_

Month	Column 1	Column 2	Column 1 + Column 2
	Limestone (Tons)	Limestone (Tons)	Limestone (Tons)
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

- No deviation occurred in this quarter.
- Deviation/s occurred in this quarter.  
Deviation has been reported on: \_\_\_\_\_

Submitted by: \_\_\_\_\_

Title / Position: \_\_\_\_\_

Signature: \_\_\_\_\_

Date: \_\_\_\_\_

Phone: \_\_\_\_\_

**INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT  
OFFICE OF AIR QUALITY  
COMPLIANCE AND ENFORCEMENT BRANCH**

**Part 70 Quarterly Report**

Source Name: Duke Energy Indiana, LLC - Cayuga Generating Station  
Source Address: 3300 N SR 63, Cayuga, Indiana 47928  
Part 70 Permit No.: T165-47094-00001  
Facility: Gypsum Handling System  
Parameter: Amount of gypsum received  
Limit: Less than 900,528 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

QUARTER: \_\_\_\_\_ YEAR: \_\_\_\_\_

Month	Column 1	Column 2	Column 1 + Column 2
	Gypsum (Tons)	Gypsum (Tons)	Gypsum (Tons)
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

- No deviation occurred in this quarter.
- Deviation/s occurred in this quarter.  
Deviation has been reported on: \_\_\_\_\_

Submitted by: \_\_\_\_\_

Title / Position: \_\_\_\_\_

Signature: \_\_\_\_\_

Date: \_\_\_\_\_

Phone: \_\_\_\_\_

**INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT  
OFFICE OF AIR QUALITY  
COMPLIANCE AND ENFORCEMENT BRANCH**

**Part 70 Quarterly Report**

Source Name: Duke Energy Indiana, LLC - Cayuga Generating Station  
Source Address: 3300 N SR 63, Cayuga, Indiana 47928  
Part 70 Permit No.: T165-47094-00001  
Facility: Auxiliary Boiler (Aux)  
Parameter: Fuel Usage  
Limit: Less than 455.2697 kilogallons of no. 2 fuel oil per twelve (12) consecutive month period with compliance determined at the end of each month.

QUARTER: \_\_\_\_\_ YEAR: \_\_\_\_\_

Month	Column 1	Column 2	Column 1 + Column 2
	Fuel Oil Usage (Kgal)	Fuel Oil Usage (Kgal)	Fuel Oil Usage (Kgal)
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

- No deviation occurred in this quarter.
- Deviation/s occurred in this quarter.  
Deviation has been reported on: \_\_\_\_\_

Submitted by: \_\_\_\_\_

Title / Position: \_\_\_\_\_

Signature: \_\_\_\_\_

Date: \_\_\_\_\_

Phone: \_\_\_\_\_

**INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT  
 OFFICE OF AIR QUALITY  
 COMPLIANCE AND ENFORCEMENT BRANCH  
 PART 70 OPERATING PERMIT  
 QUARTERLY DEVIATION AND COMPLIANCE MONITORING REPORT**

Source Name: Duke Energy Indiana, LLC - Cayuga Generating Station  
 Source Address: 3300 N SR 63, Cayuga, Indiana 47928  
 Part 70 Permit No.: T165-47094-00001

Months: \_\_\_\_\_ to \_\_\_\_\_ Year: \_\_\_\_\_

This report shall be submitted quarterly based on a calendar year. Proper notice submittal under Section B - Emergency Provisions satisfies the reporting requirements of paragraph (a) of Section C- General Reporting. Any deviation from the requirements of this permit, the date(s) of each deviation, the probable cause of the deviation, and the response steps taken must be reported. A deviation required to be reported pursuant to an applicable requirement that exists independent of the permit, shall be reported according to the schedule stated in the applicable requirement and does not need to be included in this report. Additional pages may be attached if necessary. If no deviations occurred, please specify in the box marked "No deviations occurred this reporting period".	
<input type="checkbox"/> NO DEVIATIONS OCCURRED THIS REPORTING PERIOD.	
<input type="checkbox"/> THE FOLLOWING DEVIATIONS OCCURRED THIS REPORTING PERIOD	
<b>Permit Requirement</b> (specify permit condition #)	
<b>Date of Deviation:</b>	<b>Duration of Deviation:</b>
<b>Number of Deviations:</b>	
<b>Probable Cause of Deviation:</b>	
<b>Response Steps Taken:</b>	
<b>Permit Requirement</b> (specify permit condition #)	
<b>Date of Deviation:</b>	<b>Duration of Deviation:</b>
<b>Number of Deviations:</b>	
<b>Probable Cause of Deviation:</b>	
<b>Response Steps Taken:</b>	

<b>Permit Requirement (specify permit condition #)</b>	
<b>Date of Deviation:</b>	<b>Duration of Deviation:</b>
<b>Number of Deviations:</b>	
<b>Probable Cause of Deviation:</b>	
<b>Response Steps Taken:</b>	
<b>Permit Requirement (specify permit condition #)</b>	
<b>Date of Deviation:</b>	<b>Duration of Deviation:</b>
<b>Number of Deviations:</b>	
<b>Probable Cause of Deviation:</b>	
<b>Response Steps Taken:</b>	
<b>Permit Requirement (specify permit condition #)</b>	
<b>Date of Deviation:</b>	<b>Duration of Deviation:</b>
<b>Number of Deviations:</b>	
<b>Probable Cause of Deviation:</b>	
<b>Response Steps Taken:</b>	

Form Completed by: \_\_\_\_\_

Title / Position: \_\_\_\_\_

Date: \_\_\_\_\_

Phone: \_\_\_\_\_

## Attachment A

### Part 70 Operating Permit No: 165-47094-00001

[Downloaded from the eCFR on March 29, 2023]

#### Electronic Code of Federal Regulations

#### Title 40: Protection of Environment

#### PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

#### Subpart JJJJ—Standards of Performance for Stationary Spark Ignition Internal Combustion Engines

SOURCE: 73 FR 3591, Jan. 18, 2008, unless otherwise noted.

#### What This Subpart Covers

#### § 60.4230 Am I subject to this subpart?

(a) The provisions of this subpart are applicable to manufacturers, owners, and operators of stationary spark ignition (SI) internal combustion engines (ICE) as specified in paragraphs (a)(1) through (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.

[73 FR 3591, Jan. 18, 2008, as amended at 76 FR 37972, June 28, 2011; 86 FR 34360, June 29, 2021]

### **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:

<b>If engine displacement is . . .</b>	<b>and manufacturing dates are . . .</b>	<b>the engine must meet the following non-handheld emission standards identified in 40 CFR part 1054 and related requirements:</b>
(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.

[73 FR 3591, Jan. 18, 2008, as amended at 73 FR 59175, Oct. 8, 2008; 76 FR 37973, June 28, 2011; 78 FR 6697, Jan. 30, 2013; 86 FR 34360, June 29, 2021]

**§ 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<sub>x</sub>) 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<sub>x</sub> emission standard of 250 ppmvd at 15 percent oxygen (O<sub>2</sub>), a CO emission standard 540 ppmvd at 15 percent O<sub>2</sub> (675 ppmvd at 15 percent O<sub>2</sub> for non-emergency engines less than 100 HP), and a VOC emission standard of 86 ppmvd at 15 percent O<sub>2</sub>, 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.

[73 FR 3591, Jan. 18, 2008, as amended at 76 FR 37973, June 28, 2011]

**§ 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.

[73 FR 3591, Jan. 18, 2008, as amended at 85 FR 78463, Dec. 4, 2020]

**§ 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.

[86 FR 34361, June 29, 2021]

**§ 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.

[86 FR 34361, June 29, 2021]

**§ 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.

[86 FR 34361, June 29, 2021]

**§ 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.

[73 FR 3591, Jan. 18, 2008, as amended at 73 FR 59176, Oct. 8, 2008; 76 FR 37974, June 28, 2011; 86 FR 34361, June 29, 2021]

**§ 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.

[86 FR 34362, June 29, 2021]

### **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)-(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.

[73 FR 3591, Jan. 18, 2008, as amended at 76 FR 37974, June 28, 2011; 78 FR 6697, Jan. 30, 2013; 86 FR 34362, June 29, 2021; 87 FR 48606, Aug. 10, 2022]

#### 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<sub>x</sub> mass per unit output emission limitation, convert the concentration of NO<sub>x</sub> in the engine exhaust using Equation 1 of this section:

$$ER = \frac{C_d \times 1.912 \times 10^{-3} \times Q \times T}{HP - hr} \quad (\text{Eq. 1})$$

Where:

ER = Emission rate of NO<sub>x</sub> in g/HP-hr.

$C_d$  = Measured  $\text{NO}_x$  concentration in parts per million by volume (ppmv).

$1.912 \times 10^{-3}$  = Conversion constant for ppm  $\text{NO}_x$  to grams per standard cubic meter at 20 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour, dry basis.

T = Time of test run, in hours.

HP-hr = Brake work of the engine, horsepower-hour (HP-hr).

(e) To determine compliance with the CO mass per unit output emission limitation, convert the concentration of CO in the engine exhaust using Equation 2 of this section:

$$ER = \frac{C_d \times 1.164 \times 10^{-3} \times Q \times T}{HP - hr} \quad (\text{Eq. 2})$$

Where:

ER = Emission rate of CO in g/HP-hr.

$C_d$  = Measured CO concentration in ppmv.

$1.164 \times 10^{-3}$  = Conversion constant for ppm CO to grams per standard cubic meter at 20 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meters per hour, dry basis.

T = Time of test run, in hours.

HP-hr = Brake work of the engine, in HP-hr.

(f) For purposes of this subpart, when calculating emissions of VOC, emissions of formaldehyde should not be included. To determine compliance with the VOC mass per unit output emission limitation, convert the concentration of VOC in the engine exhaust using Equation 3 of this section:

$$ER = \frac{C_d \times 1.833 \times 10^{-3} \times Q \times T}{HP - hr} \quad (\text{Eq. 3})$$

Where:

ER = Emission rate of VOC in g/HP-hr.

$C_d$  = VOC concentration measured as propane in ppmv.

$1.833 \times 10^{-3}$  = 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.

$$C_{icorr} = RF_i \times C_{imeas} \quad (\text{Eq. 5})$$

Where:

$C_{icorr}$  = Concentration of compound i corrected to the value that would have been measured by EPA Method 25A, ppmv as carbon.

$C_{imeas}$  = Concentration of compound i measured by EPA Method 320, ppmv as carbon.

$$C_{Peq} = 0.6098 \times C_{icorr} \quad (\text{Eq. 6})$$

Where:

$C_{Peq}$  = Concentration of compound i in mg of propane equivalent per DSCM.

#### Notification, Reports, and Records for Owners and Operators

##### § 60.4245 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary SI internal combustion engine?

Owners or operators of stationary SI ICE must meet the following notification, reporting and recordkeeping requirements.

(a) Owners and operators of all stationary SI ICE must keep records of the information in paragraphs (a)(1) through (4) of this section.

(1) All notifications submitted to comply with this subpart and all documentation supporting any notification.

(2) Maintenance conducted on the engine.

(3) If the stationary SI internal combustion engine is a certified engine, documentation from the manufacturer that the engine is certified to meet the emission standards and information as required in 40 CFR parts 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.

(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.

(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) ([www.epa.gov/cdx](http://www.epa.gov/cdx)). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in § 60.4.

[73 FR 3591, Jan. 18, 2008, as amended at 73 FR 59177, Oct. 8, 2008; 78 FR 6697, Jan. 30, 2013; 81 FR 59809, Aug. 30, 2016; 86 FR 34362, June 29, 2021; 87 FR 48606, Aug. 10, 2022]

## 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.

[88 FR 4471, Jan. 24, 2023]

## 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.

[73 FR 3591, Jan. 18, 2008, as amended at 73 FR 59177, Oct. 8, 2008; 86 FR 34362, June 29, 2021]

## 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 (CO<sub>2</sub>).

*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 CO<sub>2</sub>.

*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<sub>x</sub> (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 P, 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.

[73 FR 3591, Jan. 18, 2008, as amended at 73 FR 59177, Oct. 8, 2008; 76 FR 37974, June 28, 2011; 78 FR 6698, Jan. 30, 2013; 86 FR 34363, June 29, 2021; 87 FR 48606, Aug. 10, 2022]

**Table 1 to Subpart JJJJ of Part 60—NO<sub>x</sub>, 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 <sup>a</sup>					
			g/HP-hr			ppmvd at 15% O <sub>2</sub>		
			NO <sub>x</sub>	CO	VOC <sup>d</sup>	NO <sub>x</sub>	CO	VOC <sup>d</sup>
Non-Emergency SI Natural Gas <sup>b</sup> and Non-Emergency SI Lean Burn LPG <sup>b</sup>	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	<sup>c</sup> 10	387	N/A	N/A	N/A	N/A
	HP≥130		2.0	4.0	1.0	160	540	86

<sup>a</sup>Owners and operators of stationary non-certified SI engines may choose to comply with the emission standards in units of either g/HP-hr or ppmvd at 15 percent O<sub>2</sub>.

<sup>b</sup>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.

<sup>c</sup>The emission standards applicable to emergency engines between 25 HP and 130 HP are in terms of NO<sub>x</sub> + HC.

<sup>d</sup>For purposes of this subpart, when calculating emissions of volatile organic compounds, emissions of formaldehyde should not be included.

[76 FR 37975, June 28, 2011]

**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 <sub>x</sub> 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 <sub>x</sub> , O <sub>2</sub> , 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 <sub>2</sub> concentration of the stationary internal combustion engine exhaust at the sampling port location;	(2) Method 3, 3A, or 3B <sup>b</sup> of 40 CFR part 60, appendix A-2 or ASTM Method D6522-00 (Reapproved 2005) <sup>ad</sup>	(b) Measurements to determine O <sub>2</sub> concentration must be made at the same time as the measurements for NO <sub>x</sub> 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 <sub>x</sub> 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, <sup>e</sup> or ASTM Method D6348-03 <sup>de</sup>	(d) Measurements to determine moisture must be made at the same time as the measurement for NO <sub>x</sub> concentration.

For each	Complying with the requirement to	You must	Using	According to the following requirements
		v. Measure NO <sub>x</sub> at the exhaust of the stationary internal combustion engine; if using a control device, the sampling site must be located at the outlet of the control device	(5) Method 7E of 40 CFR part 60, appendix A-4, ASTM Method D6522-00 (Reapproved 2005), <sup>ad</sup> Method 320 of 40 CFR part 63, appendix A, <sup>e</sup> or ASTM Method D6348-03 <sup>de</sup>	(e) Results of this test consist of the average of the three 1-hour or longer runs.
	b. Limit the concentration of CO in the stationary SI internal combustion engine exhaust	i. Select the sampling port location and the number/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 <sub>2</sub> , 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 <sub>2</sub> concentration of the stationary internal combustion engine exhaust at the sampling port location;	(2) Method 3, 3A, or 3B <sup>b</sup> of 40 CFR part 60, appendix A-2 or ASTM Method D6522-00 (Reapproved 2005) <sup>ad</sup>	(b) Measurements to determine O <sub>2</sub> 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, <sup>e</sup> or ASTM Method D6348-03 <sup>de</sup>	(d) Measurements to determine moisture must be made at the same time as the measurement for CO concentration.

For each	Complying with the requirement to	You must	Using	According to the following requirements
		v. Measure CO at the exhaust of the stationary internal combustion engine; if using a control device, the sampling site must be located at the outlet of the control device	(5) Method 10 of 40 CFR part 60, appendix A4, ASTM Method D6522-00 (Reapproved 2005), <sup>ade</sup> Method 320 of 40 CFR part 63, appendix A, <sup>e</sup> or ASTM Method D6348-03 <sup>de</sup>	(e) Results of this test consist of the average of the three 1-hour or longer runs.
	c. Limit the concentration of VOC in the stationary SI internal combustion engine exhaust	i. Select the sampling port location and the number/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 <sub>2</sub> , 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 <sub>2</sub> concentration of the stationary internal combustion engine exhaust at the sampling port location;	(2) Method 3, 3A, or 3B <sup>b</sup> of 40 CFR part 60, appendix A-2 or ASTM Method D6522-00 (Reapproved 2005) <sup>ad</sup>	(b) Measurements to determine O <sub>2</sub> 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 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, <sup>e</sup> or ASTM Method D6348-03 <sup>de</sup>	(d) Measurements to determine moisture must be made at the same time as the measurement for VOC concentration.

For each	Complying with the requirement to	You must	Using	According to the following requirements
		v. Measure VOC at the exhaust of the stationary internal combustion engine; 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, <sup>ce</sup> Method 320 of 40 CFR part 63, appendix A, <sup>e</sup> or ASTM Method D6348-03 <sup>de</sup>	(e) Results of this test consist of the average of the three 1-hour or longer runs.

<sup>a</sup>Also, you may petition the Administrator for approval to use alternative methods for portable analyzer.

<sup>b</sup>You may use ASME PTC 19.10-1981, Flue and Exhaust Gas Analyses, for measuring the O<sub>2</sub> 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

<sup>c</sup>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>).

<sup>d</sup>Incorporated by reference; see 40 CFR 60.17.

<sup>e</sup>You must meet the requirements in §60.4245(d).

[85 FR 63408, Oct. 7, 2020]

**Table 3 to Subpart JJJJ of Part 60—Applicability of General Provisions to Subpart JJJJ**

[As stated in §60.4246, you must comply with the following applicable General Provisions]

General provisions citation	Subject of citation	Applies to subpart	Explanation
§60.1	General applicability of the General Provisions	Yes	
§60.2	Definitions	Yes	Additional terms defined in §60.4248.
§60.3	Units and abbreviations	Yes	
§60.4	Address	Yes	
§60.5	Determination of construction or modification	Yes	
§60.6	Review of plans	Yes	
§60.7	Notification and Recordkeeping	Yes	Except that §60.7 only applies as specified in §60.4245.

General provisions citation	Subject of citation	Applies to subpart	Explanation
§60.8	Performance tests	Yes	Except that §60.8 only applies to owners and operators who are subject to performance testing in subpart JJJJ.
§60.9	Availability of information	Yes	
§60.10	State Authority	Yes	
§60.11	Compliance with standards and maintenance requirements	Yes	Requirements are specified in subpart JJJJ.
§60.12	Circumvention	Yes	
§60.13	Monitoring requirements	No	
§60.14	Modification	Yes	
§60.15	Reconstruction	Yes	
§60.16	Priority list	Yes	
§60.17	Incorporations by reference	Yes	
§60.18	General control device requirements	No	
§60.19	General notification and reporting requirements	Yes	

**Table 4 to Subpart JJJJ of Part 60—Applicability of Mobile Source Provisions for Manufacturers Participating in the Voluntary Certification Program and Certifying Stationary SI ICE to Emission Standards in Table 1 of Subpart JJJJ**

[As stated in §60.4247, you must comply with the following applicable mobile source provisions if you are a manufacturer participating in the voluntary certification program and certifying stationary SI ICE to emission standards in Table 1 of subpart JJJJ]

Mobile source provisions citation	Subject of citation	Applies to subpart	Explanation
1048 subpart A	Overview and Applicability	Yes	
1048 subpart B	Emission Standards and Related Requirements	Yes	Except for the specific sections below.
1048.101	Exhaust Emission Standards	No	
1048.105	Evaporative Emission Standards	No	
1048.110	Diagnosing Malfunctions	No	
1048.140	Certifying Blue Sky Series Engines	No	
1048.145	Interim Provisions	No	
1048 subpart C	Certifying Engine Families	Yes	Except for the specific sections below.
1048.205(b)	AECD reporting	Yes	
1048.205(c)	OBD Requirements	No	

<b>Mobile source provisions citation</b>	<b>Subject of citation</b>	<b>Applies to subpart</b>	<b>Explanation</b>
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	



## Attachment B

### Part 70 Operating Permit No: 165-47094-00001

[Downloaded from the eCFR on May 13, 2013]

#### Electronic Code of Federal Regulations

#### Title 40: Protection of Environment

#### PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

#### Subpart 000—Standards of Performance for Nonmetallic Mineral Processing Plants

Source: 74 FR 19309, Apr. 28, 2009, unless otherwise noted.

#### § 60.670 Applicability and designation of affected facility.

(a)(1) Except as provided in paragraphs (a)(2), (b), (c), and (d) of this section, the provisions of this subpart are applicable to the following affected facilities in fixed or portable nonmetallic mineral processing plants: each crusher, grinding mill, screening operation, bucket elevator, belt conveyor, bagging operation, storage bin, enclosed truck or railcar loading station. Also, crushers and grinding mills at hot mix asphalt facilities that reduce the size of nonmetallic minerals embedded in recycled asphalt pavement and subsequent affected facilities up to, but not including, the first storage silo or bin are subject to the provisions of this subpart.

(2) The provisions of this subpart do not apply to the following operations: All facilities located in underground mines; plants without crushers or grinding mills above ground; and wet material processing operations (as defined in § 60.671).

(b) An affected facility that is subject to the provisions of subparts F or I of this part or that follows in the plant process any facility subject to the provisions of subparts F or I of this part is not subject to the provisions of this subpart.

(c) Facilities at the following plants are not subject to the provisions of this subpart:

(1) Fixed sand and gravel plants and crushed stone plants with capacities, as defined in § 60.671, of 23 megagrams per hour (25 tons per hour) or less;

(2) Portable sand and gravel plants and crushed stone plants with capacities, as defined in § 60.671, of 136 megagrams per hour (150 tons per hour) or less; and

(3) Common clay plants and pumice plants with capacities, as defined in § 60.671, of 9 megagrams per hour (10 tons per hour) or less.

(d)(1) When an existing facility is replaced by a piece of equipment of equal or smaller size, as defined in § 60.671, having the same function as the existing facility, and there is no increase in the amount of emissions, the new facility is exempt from the provisions of §§ 60.672, 60.674, and 60.675 except as provided for in paragraph (d)(3) of this section.

(2) An owner or operator complying with paragraph (d)(1) of this section shall submit the information required in § 60.676(a).

(3) An owner or operator replacing all existing facilities in a production line with new facilities does not qualify for the exemption described in paragraph (d)(1) of this section and must comply with the provisions of §§ 60.672, 60.674 and 60.675.

(e) An affected facility under paragraph (a) of this section that commences construction, modification, or reconstruction after August 31, 1983, is subject to the requirements of this part.

(f) Table 1 of this subpart specifies the provisions of subpart A of this part 60 that do not apply to owners and operators of affected facilities subject to this subpart or that apply with certain exceptions.

**§ 60.671 Definitions.**

All terms used in this subpart, but not specifically defined in this section, shall have the meaning given them in the Act and in subpart A of this part.

*Bagging operation* means the mechanical process by which bags are filled with nonmetallic minerals.

*Belt conveyor* means a conveying device that transports material from one location to another by means of an endless belt that is carried on a series of idlers and routed around a pulley at each end.

*Bucket elevator* means a conveying device of nonmetallic minerals consisting of a head and foot assembly which supports and drives an endless single or double strand chain or belt to which buckets are attached.

*Building* means any frame structure with a roof.

*Capacity* means the cumulative rated capacity of all initial crushers that are part of the plant.

*Capture system* means the equipment (including enclosures, hoods, ducts, fans, dampers, etc.) used to capture and transport particulate matter generated by one or more affected facilities to a control device.

*Control device* means the air pollution control equipment used to reduce particulate matter emissions released to the atmosphere from one or more affected facilities at a nonmetallic mineral processing plant.

*Conveying system* means a device for transporting materials from one piece of equipment or location to another location within a plant. Conveying systems include but are not limited to the following: Feeders, belt conveyors, bucket elevators and pneumatic systems.

*Crush* or *Crushing* means to reduce the size of nonmetallic mineral material by means of physical impaction of the crusher or grinding mill upon the material.

*Crusher* means a machine used to crush any nonmetallic minerals, and includes, but is not limited to, the following types: Jaw, gyratory, cone, roll, rod mill, hammermill, and impactor.

*Enclosed truck or railcar loading station* means that portion of a nonmetallic mineral processing plant where nonmetallic minerals are loaded by an enclosed conveying system into enclosed trucks or railcars.

*Fixed plant* means any nonmetallic mineral processing plant at which the processing equipment specified in § 60.670(a) is attached by a cable, chain, turnbuckle, bolt or other means (except electrical connections) to any anchor, slab, or structure including bedrock.

*Fugitive emission* means particulate matter that is not collected by a capture system and is released to the atmosphere at the point of generation.

*Grinding mill* means a machine used for the wet or dry fine crushing of any nonmetallic mineral. Grinding mills include, but are not limited to, the following types: Hammer, roller, rod, pebble and ball, and fluid energy. The grinding mill includes the air conveying system, air separator, or air classifier, where such systems are used.

*Initial crusher* means any crusher into which nonmetallic minerals can be fed without prior crushing in the plant.

*Nonmetallic mineral* means any of the following minerals or any mixture of which the majority is any of the following minerals:

(1) Crushed and Broken Stone, including Limestone, Dolomite, Granite, Traprock, Sandstone, Quartz, Quartzite, Marl, Marble, Slate, Shale, Oil Shale, and Shell.

(2) Sand and Gravel.

(3) Clay including Kaolin, Fireclay, Bentonite, Fuller's Earth, Ball Clay, and Common Clay.

(4) Rock Salt.

(5) Gypsum (natural or synthetic).

(6) Sodium Compounds, including Sodium Carbonate, Sodium Chloride, and Sodium Sulfate.

(7) Pumice.

(8) Gilsonite.

(9) Talc and Pyrophyllite.

(10) Boron, including Borax, Kernite, and Colemanite.

(11) Barite.

(12) Fluorospar.

(13) Feldspar.

(14) Diatomite.

(15) Perlite.

(16) Vermiculite.

(17) Mica.

(18) Kyanite, including Andalusite, Sillimanite, Topaz, and Dumortierite.

*Nonmetallic mineral processing plant* means any combination of equipment that is used to crush or grind any nonmetallic mineral wherever located, including lime plants, power plants, steel mills, asphalt concrete plants, portland cement plants, or any other facility processing nonmetallic minerals except as provided in § 60.670 (b) and (c).

*Portable plant* means any nonmetallic mineral processing plant that is mounted on any chassis or skids and may be moved by the application of a lifting or pulling force. In addition, there shall be no cable, chain, turnbuckle, bolt or other means (except electrical connections) by which any piece of equipment is attached or clamped to any anchor, slab, or structure, including bedrock that must be removed prior to the application of a lifting or pulling force for the purpose of transporting the unit.

*Production line* means all affected facilities (crushers, grinding mills, screening operations, bucket elevators, belt conveyors, bagging operations, storage bins, and enclosed truck and railcar loading stations) which are directly connected or are connected together by a conveying system.

*Saturated material* means, for purposes of this subpart, mineral material with sufficient surface moisture such that particulate matter emissions are not generated from processing of the material through screening operations, bucket elevators and belt conveyors. Material that is wetted solely by wet suppression systems is not considered to be "saturated" for purposes of this definition.

*Screening operation* means a device for separating material according to size by passing undersize material through one or more mesh surfaces (screens) in series, and retaining oversize material on the mesh surfaces (screens). Grizzly feeders associated with truck dumping and static (non-moving) grizzlies used anywhere in the nonmetallic mineral processing plant are not considered to be screening operations.

*Seasonal shut down* means shut down of an affected facility for a period of at least 45 consecutive days due to weather or seasonal market conditions.

*Size* means the rated capacity in tons per hour of a crusher, grinding mill, bucket elevator, bagging operation, or enclosed truck or railcar loading station; the total surface area of the top screen of a screening operation; the width of a conveyor belt; and the rated capacity in tons of a storage bin.

*Stack emission* means the particulate matter that is released to the atmosphere from a capture system.

*Storage bin* means a facility for storage (including surge bins) of nonmetallic minerals prior to further processing or loading.

*Transfer point* means a point in a conveying operation where the nonmetallic mineral is transferred to or from a belt conveyor except where the nonmetallic mineral is being transferred to a stockpile.

*Truck dumping* means the unloading of nonmetallic minerals from movable vehicles designed to transport nonmetallic minerals from one location to another. Movable vehicles include but are not limited to: Trucks, front end loaders, skip hoists, and railcars.

*Vent* means an opening through which there is mechanically induced air flow for the purpose of exhausting from a building air carrying particulate matter emissions from one or more affected facilities.

*Wet material processing operation(s)* means any of the following:

- (1) Wet screening operations (as defined in this section) and subsequent screening operations, bucket elevators and belt conveyors in the production line that process saturated materials (as defined in this section) up to the first crusher, grinding mill or storage bin in the production line; or
- (2) Screening operations, bucket elevators and belt conveyors in the production line downstream of wet mining operations (as defined in this section) that process saturated materials (as defined in this section) up to the first crusher, grinding mill or storage bin in the production line.

*Wet mining operation* means a mining or dredging operation designed and operated to extract any nonmetallic mineral regulated under this subpart from deposits existing at or below the water table, where the nonmetallic mineral is saturated with water.

*Wet screening operation* means a screening operation at a nonmetallic mineral processing plant which removes unwanted material or which separates marketable fines from the product by a washing process which is designed and operated at all times such that the product is saturated with water.

#### **§ 60.672 Standard for particulate matter (PM).**

(a) Affected facilities must meet the stack emission limits and compliance requirements in Table 2 of this subpart 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 as required under § 60.8. The requirements in Table 2 of this subpart apply for affected facilities with capture systems used to capture and transport particulate matter to a control device.

(b) Affected facilities must meet the fugitive emission limits and compliance requirements in Table 3 of this subpart 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 as required under § 60.11. The requirements in Table 3 of this subpart apply for fugitive emissions from affected facilities without capture systems and for fugitive emissions escaping capture systems.

(c) [Reserved]

(d) Truck dumping of nonmetallic minerals into any screening operation, feed hopper, or crusher is exempt from the requirements of this section.

(e) If any transfer point on a conveyor belt or any other affected facility is enclosed in a building, then each enclosed affected facility must comply with the emission limits in paragraphs (a) and (b) of this section, or the building enclosing the affected facility or facilities must comply with the following emission limits:

(1) Fugitive emissions from the building openings (except for vents as defined in § 60.671) must not exceed 7 percent opacity; and

(2) Vents (as defined in § 60.671) in the building must meet the applicable stack emission limits and compliance requirements in Table 2 of this subpart.

(f) Any baghouse that controls emissions from only an individual, enclosed storage bin is exempt from the applicable stack PM concentration limit (and associated performance testing) in Table 2 of this subpart but must meet the applicable stack opacity limit and compliance requirements in Table 2 of this subpart. This exemption from the stack PM concentration limit does not apply for multiple storage bins with combined stack emissions.

#### **§ 60.673 Reconstruction.**

(a) The cost of replacement of ore-contact surfaces on processing equipment shall not be considered in calculating either the "fixed capital cost of the new components" or the "fixed capital cost that would be required to construct a comparable new facility" under § 60.15. Ore-contact surfaces are crushing surfaces; screen meshes, bars, and plates; conveyor belts; and elevator buckets.

(b) Under § 60.15, the "fixed capital cost of the new components" includes the fixed capital cost of all depreciable components (except components specified in paragraph (a) of this section) which are or will be replaced pursuant to all continuous programs of component replacement commenced within any 2-year period following August 31, 1983.

#### **§ 60.674 Monitoring of operations.**

(a) The owner or operator of any affected facility subject to the provisions of this subpart which uses a wet scrubber to control emissions shall install, calibrate, maintain and operate the following monitoring devices:

(1) A device for the continuous measurement of the pressure loss of the gas stream through the scrubber. The monitoring device must be certified by the manufacturer to be accurate within  $\pm 250$  pascals  $\pm 1$  inch water gauge pressure and must be calibrated on an annual basis in accordance with manufacturer's instructions.

(2) A device for the continuous measurement of the scrubbing liquid flow rate to the wet scrubber. The monitoring device must be certified by the manufacturer to be accurate within  $\pm 5$  percent of design scrubbing liquid flow rate and must be calibrated on an annual basis in accordance with manufacturer's instructions.

(b) The owner or operator of any affected facility for which construction, modification, or reconstruction commenced on or after April 22, 2008, that uses wet suppression to control emissions from the affected facility must perform monthly periodic inspections to check that water is flowing to discharge spray nozzles in the wet suppression system. The owner or operator must initiate corrective action within 24 hours and complete corrective action as expeditiously as practical if the owner or operator finds that water is not flowing properly during an inspection of the water spray nozzles. The owner or operator must record each inspection of the water spray nozzles, including the date of each inspection and any corrective actions taken, in the logbook required under § 60.676(b).

(1) If an affected facility relies on water carryover from upstream water sprays to control fugitive emissions, then that affected facility is exempt from the 5-year repeat testing requirement specified in Table 3 of this subpart provided that the affected facility meets the criteria in paragraphs (b)(1)(i) and (ii) of this section:

(i) The owner or operator of the affected facility conducts periodic inspections of the upstream water spray(s) that are responsible for controlling fugitive emissions from the affected facility. These inspections are conducted according to paragraph (b) of this section and § 60.676(b), and

(ii) The owner or operator of the affected facility designates which upstream water spray(s) will be periodically inspected at the time of the initial performance test required under § 60.11 of this part and § 60.675 of this subpart.

(2) If an affected facility that routinely uses wet suppression water sprays ceases operation of the water sprays or is using a control mechanism to reduce fugitive emissions other than water sprays during the monthly inspection (for example, water from recent rainfall), the logbook entry required under § 60.676(b) must specify the control mechanism being used instead of the water sprays.

(c) Except as specified in paragraph (d) or (e) of this section, the owner or operator of any affected facility for which construction, modification, or reconstruction commenced on or after April 22, 2008, that uses a baghouse to control emissions must conduct quarterly 30-minute visible emissions inspections using EPA Method 22 (40 CFR part 60, Appendix A-7). The Method 22 (40 CFR part 60, Appendix A-7) test shall be conducted while the baghouse is operating. The test is successful if no visible emissions are observed. If any visible emissions are observed, the owner or operator of the affected facility must initiate corrective action within 24 hours to return the baghouse to normal operation. The owner or operator must record each Method 22 (40 CFR part 60, Appendix A-7) test, including the date and any corrective actions taken, in the logbook required under § 60.676(b). The owner or operator of the affected facility may establish a different baghouse-specific success level for the visible emissions test (other than no visible emissions) by conducting a PM performance test according to § 60.675(b) simultaneously with a Method 22 (40 CFR part 60, Appendix A-7) to determine what constitutes normal visible emissions from that affected facility's baghouse when it is in compliance with the applicable PM concentration limit in Table 2 of this subpart. The revised visible emissions success level must be incorporated into the permit for the affected facility.

(d) As an alternative to the periodic Method 22 (40 CFR part 60, Appendix A-7) visible emissions inspections specified in paragraph (c) of this section, the owner or operator of any affected facility for which construction, modification, or reconstruction commenced on or after April 22, 2008, that uses a baghouse to control emissions may use a bag leak detection system. The owner or operator must install, operate, and maintain the bag leak detection system according to paragraphs (d)(1) through (3) of this section.

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

(i) The bag leak detection system must be certified by the manufacturer to be capable of detecting PM emissions at concentrations of 1 milligram per dry standard cubic meter (0.00044 grains per actual cubic foot) or less.

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

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

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

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

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

(vii) The owner or operator must install the bag leak detection sensor downstream of the fabric filter.

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

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

(i) Installation of the bag leak detection system;

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

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

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

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

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

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

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

(ii) Sealing off defective bags or filter media;

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

(iv) Sealing off a defective fabric filter compartment;

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

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

(e) As an alternative to the periodic Method 22 (40 CFR part 60, Appendix A-7) visible emissions inspections specified in paragraph (c) of this section, the owner or operator of any affected facility that is subject to the requirements for processed stone handling operations in the Lime Manufacturing NESHAP (40 CFR part 63, subpart AAAAA) may follow the continuous compliance requirements in row 1 items (i) through (iii) of Table 6 to Subpart AAAAA of 40 CFR part 63.

**§ 60.675 Test methods and procedures.**

(a) In conducting the performance tests required in § 60.8, the owner or operator shall use as reference methods and procedures the test methods in appendices A-1 through A-7 of this part or other methods and procedures as specified in this section, except as provided in § 60.8(b). Acceptable alternative methods and procedures are given in paragraph (e) of this section.

(b) The owner or operator shall determine compliance with the PM standards in § 60.672(a) as follows:

(1) Except as specified in paragraphs (e)(3) and (4) of this section, Method 5 of Appendix A-3 of this part or Method 17 of Appendix A-6 of this part shall be used to determine the particulate matter concentration. The sample volume shall be at least 1.70 dscm (60 dscf). For Method 5 (40 CFR part 60, Appendix A-3), if the gas stream being sampled is at ambient temperature, the sampling probe and filter may be operated without heaters. If the gas stream is above ambient temperature, the sampling probe and filter may be operated at a temperature high enough, but no higher than 121 °C (250 °F), to prevent water condensation on the filter.

(2) Method 9 of Appendix A-4 of this part and the procedures in § 60.11 shall be used to determine opacity.

(c)(1) In determining compliance with the particulate matter standards in § 60.672(b) or § 60.672(e)(1), the owner or operator shall use Method 9 of Appendix A-4 of this part and the procedures in § 60.11, with the following additions:

(i) The minimum distance between the observer and the emission source shall be 4.57 meters (15 feet).

(ii) The observer shall, when possible, select a position that minimizes interference from other fugitive emission sources ( e.g., road dust). The required observer position relative to the sun (Method 9 of Appendix A-4 of this part, Section 2.1) must be followed.

(iii) For affected facilities using wet dust suppression for particulate matter control, a visible mist is sometimes generated by the spray. The water mist must not be confused with particulate matter emissions and is not to be considered a visible emission. When a water mist of this nature is present, the observation of emissions is to be made at a point in the plume where the mist is no longer visible.

(2)(i) In determining compliance with the opacity of stack emissions from any baghouse that controls emissions only from an individual enclosed storage bin under § 60.672(f) of this subpart, using Method 9 (40 CFR part 60, Appendix A-4), the duration of the Method 9 (40 CFR part 60, Appendix A-4) observations shall be 1 hour (ten 6-minute averages).

(ii) The duration of the Method 9 (40 CFR part 60, Appendix A-4) observations may be reduced to the duration the affected facility operates (but not less than 30 minutes) for baghouses that control storage bins or enclosed truck or railcar loading stations that operate for less than 1 hour at a time.

(3) When determining compliance with the fugitive emissions standard for any affected facility described under § 60.672(b) or § 60.672(e)(1) of this subpart, the duration of the Method 9 (40 CFR part 60, Appendix A-4) observations must be 30 minutes (five 6-minute averages). Compliance with the applicable fugitive emission limits in Table 3 of this subpart must be based on the average of the five 6-minute averages.

(d) To demonstrate compliance with the fugitive emission limits for buildings specified in § 60.672(e)(1), the owner or operator must complete the testing specified in paragraph (d)(1) and (2) of this section. Performance tests must be conducted while all affected facilities inside the building are operating.

(1) If the building encloses any affected facility that commences construction, modification, or reconstruction on or after April 22, 2008, the owner or operator of the affected facility must conduct an initial Method 9 (40 CFR part 60, Appendix A-4) performance test according to this section and § 60.11.

(2) If the building encloses only affected facilities that commenced construction, modification, or reconstruction before April 22, 2008, and the owner or operator has previously conducted an initial Method 22 (40 CFR part 60, Appendix A-7) performance test showing zero visible emissions, then the owner or operator has demonstrated compliance with



the opacity limit in § 60.672(e)(1). If the owner or operator has not conducted an initial performance test for the building before April 22, 2008, then the owner or operator must conduct an initial Method 9 (40 CFR part 60, Appendix A-4) performance test according to this section and § 60.11 to show compliance with the opacity limit in § 60.672(e)(1).

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

(1) For the method and procedure of paragraph (c) of this section, if emissions from two or more facilities continuously interfere so that the opacity of fugitive emissions from an individual affected facility cannot be read, either of the following procedures may be used:

(i) Use for the combined emission stream the highest fugitive opacity standard applicable to any of the individual affected facilities contributing to the emissions stream.

(ii) Separate the emissions so that the opacity of emissions from each affected facility can be read.

(2) A single visible emission observer may conduct visible emission observations for up to three fugitive, stack, or vent emission points within a 15-second interval if the following conditions are met:

(i) No more than three emission points may be read concurrently.

(ii) All three emission points must be within a 70 degree viewing sector or angle in front of the observer such that the proper sun position can be maintained for all three points.

(iii) If an opacity reading for any one of the three emission points equals or exceeds the applicable standard, then the observer must stop taking readings for the other two points and continue reading just that single point.

(3) Method 5I of Appendix A-3 of this part may be used to determine the PM concentration as an alternative to the methods specified in paragraph (b)(1) of this section. Method 5I (40 CFR part 60, Appendix A-3) may be useful for affected facilities that operate for less than 1 hour at a time such as (but not limited to) storage bins or enclosed truck or railcar loading stations.

(4) In some cases, velocities of exhaust gases from building vents may be too low to measure accurately with the type S pitot tube specified in EPA Method 2 of Appendix A-1 of this part [ *i.e.*, velocity head <1.3 mm H<sub>2</sub>O (0.05 in. H<sub>2</sub>O)] and referred to in EPA Method 5 of Appendix A-3 of this part. For these conditions, the owner or operator may determine the average gas flow rate produced by the power fans ( *e.g.*, from vendor-supplied fan curves) to the building vent. The owner or operator may calculate the average gas velocity at the building vent measurement site using Equation 1 of this section and use this average velocity in determining and maintaining isokinetic sampling rates.

$$v_e = \frac{Q_f}{A_e} \quad (\text{Eq. 1})$$

Where:

$V_e$  = average building vent velocity (feet per minute);

$Q_f$  = average fan flow rate (cubic feet per minute); and

$A_e$  = area of building vent and measurement location (square feet).

(f) To comply with § 60.676(d), the owner or operator shall record the measurements as required in § 60.676(c) using the monitoring devices in § 60.674 (a)(1) and (2) during each particulate matter run and shall determine the averages.

(g) For performance tests involving only Method 9 (40 CFR part 60 Appendix A-4) testing, the owner or operator may reduce the 30-day advance notification of performance test in § 60.7(a)(6) and 60.8(d) to a 7-day advance notification.

(h) [Reserved]

(i) If the initial performance test date for an affected facility falls during a seasonal shut down (as defined in § 60.671 of this subpart) of the affected facility, then with approval from the permitting authority, the owner or operator may postpone the initial performance test until no later than 60 calendar days after resuming operation of the affected facility.

**§ 60.676 Reporting and recordkeeping.**

(a) Each owner or operator seeking to comply with § 60.670(d) shall submit to the Administrator the following information about the existing facility being replaced and the replacement piece of equipment.

(1) For a crusher, grinding mill, bucket elevator, bagging operation, or enclosed truck or railcar loading station:

(i) The rated capacity in megagrams or tons per hour of the existing facility being replaced and

(ii) The rated capacity in tons per hour of the replacement equipment.

(2) For a screening operation:

(i) The total surface area of the top screen of the existing screening operation being replaced and

(ii) The total surface area of the top screen of the replacement screening operation.

(3) For a conveyor belt:

(i) The width of the existing belt being replaced and

(ii) The width of the replacement conveyor belt.

(4) For a storage bin:

(i) The rated capacity in megagrams or tons of the existing storage bin being replaced and

(ii) The rated capacity in megagrams or tons of replacement storage bins.

(b)(1) Owners or operators of affected facilities (as defined in §§ 60.670 and 60.671) for which construction, modification, or reconstruction commenced on or after April 22, 2008, must record each periodic inspection required under § 60.674(b) or (c), including dates and any corrective actions taken, in a logbook (in written or electronic format). The owner or operator must keep the logbook onsite and make hard or electronic copies (whichever is requested) of the logbook available to the Administrator upon request.

(2) For each bag leak detection system installed and operated according to § 60.674(d), the owner or operator must keep the records specified in paragraphs (b)(2)(i) through (iii) of this section.

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

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

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

(3) The owner or operator of each affected facility demonstrating compliance according to § 60.674(e) by following the requirements for processed stone handling operations in the Lime Manufacturing NESHAP (40 CFR part 63, subpart AAAAA) must maintain records of visible emissions observations required by § 63.7132(a)(3) and (b) of 40 CFR part 63, subpart AAAAA.

(c) During the initial performance test of a wet scrubber, and daily thereafter, the owner or operator shall record the measurements of both the change in pressure of the gas stream across the scrubber and the scrubbing liquid flow rate.

(d) After the initial performance test of a wet scrubber, the owner or operator shall submit semiannual reports to the Administrator of occurrences when the measurements of the scrubber pressure loss and liquid flow rate decrease by more than 30 percent from the average determined during the most recent performance test.

(e) The reports required under paragraph (d) of this section shall be postmarked within 30 days following end of the second and fourth calendar quarters.

(f) The owner or operator of any affected facility shall submit written reports of the results of all performance tests conducted to demonstrate compliance with the standards set forth in § 60.672 of this subpart, including reports of opacity observations made using Method 9 (40 CFR part 60, Appendix A-4) to demonstrate compliance with § 60.672(b), (e) and (f).

(g) The owner or operator of any wet material processing operation that processes saturated and subsequently processes unsaturated materials, shall submit a report of this change within 30 days following such change. At the time of such change, this screening operation, bucket elevator, or belt conveyor becomes subject to the applicable opacity limit in § 60.672(b) and the emission test requirements of § 60.11.

(h) The subpart A requirement under § 60.7(a)(1) for notification of the date construction or reconstruction commenced is waived for affected facilities under this subpart.

(i) A notification of the actual date of initial startup of each affected facility shall be submitted to the Administrator.

(1) For a combination of affected facilities in a production line that begin actual initial startup on the same day, a single notification of startup may be submitted by the owner or operator to the Administrator. The notification shall be postmarked within 15 days after such date and shall include a description of each affected facility, equipment manufacturer, and serial number of the equipment, if available.

(2) For portable aggregate processing plants, the notification of the actual date of initial startup shall include both the home office and the current address or location of the portable plant.

(j) The requirements of this section remain in force until and unless the Agency, in delegating enforcement authority to a State under section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such States. In that event, affected facilities within the State will be relieved of the obligation to comply with the reporting requirements of this section, provided that they comply with requirements established by the State.

(k) Notifications and reports required under this subpart and under subpart A of this part to demonstrate compliance with this subpart need only to be sent to the EPA Region or the State which has been delegated authority according to § 60.4(b).

**Table 1 to Subpart OOO of Part 60—Exceptions to Applicability of Subpart A to Subpart OOO**

Subpart A reference	Applies to subpart OOO	Explanation
60.4, Address	Yes	Except in § 60.4(a) and (b) submittals need not be submitted to both the EPA Region and delegated State authority (§ 60.676(k)).
60.7, Notification and recordkeeping	Yes	Except in (a)(1) notification of the date construction or reconstruction commenced (§ 60.676(h)).
		Also, except in (a)(6) performance tests involving only Method 9 (40 CFR part 60, Appendix A-4) require a 7-day advance notification instead of 30 days (§ 60.675(g)).
60.8, Performance tests	Yes	Except in (d) performance tests involving only Method 9 (40 CFR part 60, Appendix A-4) require a 7-day advance notification instead of 30 days (§ 60.675(g)).
60.11, Compliance with standards and maintenance requirements	Yes	Except in (b) under certain conditions (§§ 60.675(c)), Method 9 (40 CFR part 60, Appendix A-4) observation is reduced from 3 hours to 30 minutes for fugitive emissions.
60.18, General control device	No	Flares will not be used to comply with the emission limits.

**Table 2 to Subpart OOO of Part 60—Stack Emission Limits for Affected Facilities With Capture Systems**

For * * *	The owner or operator must meet a PM limit of * * *	And the owner or operator must meet an opacity limit of * * *	The owner or operator must demonstrate compliance with these limits by conducting * * *
Affected facilities (as defined in §§ 60.670 and 60.671) that commenced construction, modification, or reconstruction after August 31, 1983 but before April 22, 2008	0.05 g/dscm (0.022 gr/dscf) <sup>a</sup>	7 percent for dry control devices <sup>b</sup>	An initial performance test according to § 60.8 of this part and § 60.675 of this subpart; and Monitoring of wet scrubber parameters according to § 60.674(a) and § 60.676(c), (d), and (e).
Affected facilities (as defined in §§ 60.670 and 60.671) that commence construction, modification, or reconstruction on or after April 22, 2008	0.032 g/dscm (0.014 gr/dscf) <sup>a</sup>	Not applicable (except for individual enclosed storage bins) 7 percent for dry control devices on individual enclosed storage bins	An initial performance test according to § 60.8 of this part and § 60.675 of this subpart; and Monitoring of wet scrubber parameters according to § 60.674(a) and § 60.676(c), (d), and (e); and
			Monitoring of baghouses according to § 60.674(c), (d), or (e) and § 60.676(b).

<sup>a</sup> Exceptions to the PM limit apply for individual enclosed storage bins and other equipment. See § 60.672(d) through (f).

<sup>b</sup> The stack opacity limit and associated opacity testing requirements do not apply for affected facilities using wet scrubbers.

**Table 3 to Subpart OOO of Part 60—Fugitive Emission Limits**

For * * *	The owner or operator must meet the following fugitive emissions limit for grinding mills, screening operations, bucket elevators, transfer points on belt conveyors, bagging operations, storage bins, enclosed truck or railcar loading stations or from any other affected facility (as defined in §§ 60.670 and 60.671) * * *	The owner or operator must meet the following fugitive emissions limit for crushers at which a capture system is not used * * *	The owner or operator must demonstrate compliance with these limits by conducting * * *
Affected facilities (as defined in §§ 60.670 and 60.671) that commenced construction, modification, or reconstruction after August 31, 1983 but before April 22, 2008	10 percent opacity	15 percent opacity	An initial performance test according to § 60.11 of this part and § 60.675 of this subpart.
Affected facilities (as defined in §§ 60.670 and 60.671) that commence construction, modification, or reconstruction on or after April 22, 2008	7 percent opacity	12 percent opacity	An initial performance test according to § 60.11 of this part and § 60.675 of this subpart; and Periodic inspections of water sprays according to § 60.674(b) and § 60.676(b); and
			A repeat performance test according to § 60.11 of this part and § 60.675 of this subpart within 5 years from the previous performance test for fugitive emissions from affected facilities without water sprays. Affected facilities controlled by water carryover from upstream water sprays that are inspected according to the requirements in § 60.674(b) and § 60.676(b) are exempt from this 5-year repeat testing requirement.

## Attachment C

### Part 70 Operating Permit No: 165-47094-00001

[Downloaded from the eCFR on March 29, 2023]

#### Electronic Code of Federal Regulations

#### Title 40: Protection of Environment

#### PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

#### Subpart IIII—Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

Source: 71 FR 39172, July 11, 2006, unless otherwise noted.

#### What This Subpart Covers

#### § 60.4200 Am I subject to this subpart?

(a) The provisions of this subpart are applicable to manufacturers, owners, and operators of stationary compression ignition (CI) internal combustion engines (ICE) and other persons as specified in paragraphs (a)(1) through (4) 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 CI ICE with a displacement of less than 30 liters per cylinder where the model year is:

(i) 2007 or later, for engines that are not fire pump engines;

(ii) The model year listed in Table 3 to this subpart or later model year, for fire pump engines.

(2) Owners and operators of stationary CI ICE that commence construction after July 11, 2005, where the stationary CI ICE are:

(i) Manufactured after April 1, 2006, and are not fire pump engines, or

(ii) Manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.

(3) Owners and operators of any stationary CI ICE that are modified or reconstructed after July 11, 2005 and any person that modifies or reconstructs any stationary CI ICE after July 11, 2005.

(4) The provisions of § 60.4208 of this subpart are applicable to all owners and operators of stationary CI ICE that commence construction after July 11, 2005.

(b) The provisions of this subpart are not applicable to stationary CI ICE being tested at a stationary CI ICE 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 applicable to area sources.

(d) Stationary CI ICE may be eligible for exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C, except that owners and operators, as well as manufacturers, may be eligible to request an exemption for national security.

(e) Owners and operators of facilities with CI ICE 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.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37967, June 28, 2011; 86 FR 34357, June 29, 2021]

## **Emission Standards for Manufacturers**

### **§ 60.4201 What emission standards must I meet for non-emergency engines if I am a stationary CI internal combustion engine manufacturer?**

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later non-emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 kilowatt (KW) (3,000 horsepower (HP)) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 1039.101, 1039.102, 1039.104, 1039.105, 1039.107, and 1039.115 and 40 CFR part 1039, appendix I, as applicable, for all pollutants, for the same model year and maximum engine power.

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 through 2010 model year non-emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder to the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.

(c) Stationary CI internal combustion engine manufacturers must certify their 2011 model year and later non-emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 1039.101, 40 CFR 1039.102, 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, and 40 CFR 1039.115, as applicable, for all pollutants, for the same maximum engine power.

(d) Stationary CI internal combustion engine manufacturers must certify the following non-emergency stationary CI ICE to the appropriate Tier 2 emission standards for new marine CI engines as described in 40 CFR part 1042, appendix I, for all pollutants, for the same displacement and rated power:

(1) Their 2007 model year through 2012 non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder;

(2) Their 2013 model year non-emergency stationary CI ICE with a maximum engine power greater than or equal to 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

(3) Their 2013 model year non-emergency stationary CI ICE with a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

(e) Stationary CI internal combustion engine manufacturers must certify the following non-emergency stationary CI ICE to the certification emission standards and other requirements for new marine CI engines in 40 CFR 1042.101, 40 CFR 1042.107, 40 CFR 1042.110, 40 CFR 1042.115, 40 CFR 1042.120, and 40 CFR 1042.145, as applicable, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2013 model year non-emergency stationary CI ICE with a maximum engine power less than 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

(2) Their 2014 model year and later non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder.

(f) Notwithstanding the requirements in paragraphs (a) through (c) of this section, stationary non-emergency CI ICE identified in paragraphs (a) and (c) of this section may be certified to the provisions of 40 CFR part 1042 for commercial engines that are applicable for the engine's model year, displacement, power density, and maximum engine power if the engines will be used solely in either or both of the following locations:

- (1) Remote areas of Alaska; and
- (2) Marine offshore installations.

(g) Notwithstanding the requirements in paragraphs (a) through (f) of this section, stationary CI 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 CI ICE.

(h) Stationary CI ICE certified to the standards in 40 CFR part 1039 and equipped with auxiliary emission control devices (AECs) as specified in 40 CFR 1039.665 must meet the Tier 1 certification emission standards for new nonroad CI engines in 40 CFR part 1039, appendix I, while the AEC is activated during a qualified emergency situation. A qualified emergency situation is defined in 40 CFR 1039.665. When the qualified emergency situation has ended and the AEC is deactivated, the engine must resume meeting the otherwise applicable emission standard specified in this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37967, June 28, 2011; 81 FR 44219, July 7, 2016; 86 FR 34357, June 29, 2021]

**§ 60.4202 What emission standards must I meet for emergency engines if I am a stationary CI internal combustion engine manufacturer?**

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (a)(1) through (2) of this section.

(1) For engines with a maximum engine power less than 37 KW (50 HP):

(i) The Tier 2 emission standards for new nonroad CI engines for the appropriate rated power as described in 40 CFR part 1039, appendix I, for all pollutants and the smoke standards as specified in 40 CFR 1039.105 for model year 2007 engines; and

(ii) The certification emission standards for new nonroad CI engines in 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, 40 CFR 1039.115, and table 2 to this subpart, for 2008 model year and later engines.

(2) For engines with a rated power greater than or equal to 37 KW (50 HP), the Tier 2 or Tier 3 emission standards for new nonroad CI engines for the same rated power as described in 40 CFR part 1039, appendix I, for all pollutants and the smoke standards as specified in 40 CFR 1039.105 beginning in model year 2007.

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (b)(1) through (2) of this section.

(1) For 2007 through 2010 model years, the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.



(2) For 2011 model year and later, the Tier 2 emission standards as described in 40 CFR part 1039, appendix I, for all pollutants and the smoke standards as specified in 40 CFR 1039.105.

(c) [Reserved]

(d) Beginning with the model years in table 3 to this subpart, stationary CI internal combustion engine manufacturers must certify their fire pump stationary CI ICE to the emission standards in table 4 to this subpart, for all pollutants, for the same model year and NFPA nameplate power.

(e) Stationary CI internal combustion engine manufacturers must certify the following emergency stationary CI ICE that are not fire pump engines to the appropriate Tier 2 emission standards for new marine CI engines as described in 40 CFR part 1042, appendix I, for all pollutants, for the same displacement and rated power:

(1) Their 2007 model year through 2012 emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder;

(2) Their 2013 model year and later emergency stationary CI ICE with a maximum engine power greater than or equal to 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder;

(3) Their 2013 model year emergency stationary CI ICE with a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder; and

(4) Their 2014 model year and later emergency stationary CI ICE with a maximum engine power greater than or equal to 2,000 KW (2,682 HP) and a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

(f) Stationary CI internal combustion engine manufacturers must certify the following emergency stationary CI ICE to the certification emission standards and other requirements applicable to Tier 3 new marine CI engines in 40 CFR 1042.101, 40 CFR 1042.107, 40 CFR 1042.115, 40 CFR 1042.120, and 40 CFR 1042.145, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2013 model year and later emergency stationary CI ICE with a maximum engine power less than 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

(2) Their 2014 model year and later emergency stationary CI ICE with a maximum engine power less than 2,000 KW (2,682 HP) and a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

(g) Notwithstanding the requirements in paragraphs (a) through (d) of this section, stationary emergency CI ICE identified in paragraphs (a) and (c) of this section may be certified to the provisions of 40 CFR part 1042 for commercial engines that are applicable for the engine's model year, displacement, power density, and maximum engine power if the engines will be used solely in either or both of the locations identified in paragraphs (g)(1) and (2) of this section. Engines that would be subject to the Tier 4 standards in 40 CFR part 1042 that are used solely in either or both of the locations identified in paragraphs (g)(1) and (2) of this section may instead continue to be certified to the previous tier of standards in 40 CFR part 1042. The previous tier is Tier 3 in most cases; however, the previous tier is Tier 2 if there are no Tier 3 standards specified for engines of a certain size or power rating.

(1) Remote areas of Alaska; and

(2) Marine offshore installations.

(h) Notwithstanding the requirements in paragraphs (a) through (f) of this section, stationary CI 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 (f) of this

section that are applicable to the model year, maximum engine power and displacement of the reconstructed emergency stationary CI ICE.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37968, June 28, 2011; 81 FR 44219, July 7, 2016; 86 FR 34358, June 29, 2021; 88 FR 4471, Jan. 24, 2023]

**§ 60.4203 How long must my engines meet the emission standards if I am a manufacturer of stationary CI internal combustion engines?**

Engines manufactured by stationary CI internal combustion engine manufacturers must meet the emission standards as required in §§ 60.4201 and 60.4202 during the certified emissions life of the engines.

[76 FR 37968, June 28, 2011]

**Emission Standards for Owners and Operators**

**§ 60.4204 What emission standards must I meet for non-emergency engines if I am an owner or operator of a stationary CI internal combustion engine?**

(a) Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of less than 10 liters per cylinder must comply with the emission standards in table 1 to this subpart. Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder must comply with the Tier 1 emission standards in 40 CFR part 1042, appendix I.

(b) Owners and operators of 2007 model year and later non-emergency stationary CI ICE with a displacement of less than 30 liters per cylinder must comply with the emission standards for new CI engines in § 60.4201 for their 2007 model year and later stationary CI ICE, as applicable.

(c) Owners and operators of non-emergency stationary CI engines with a displacement of greater than or equal to 30 liters per cylinder must meet the following requirements:

(1) For engines installed prior to January 1, 2012, limit the emissions of NO<sub>x</sub> in the stationary CI internal combustion engine exhaust to the following:

(i) 17.0 grams per kilowatt-hour (g/KW-hr) (12.7 grams per horsepower-hr (g/HP-hr)) when maximum engine speed is less than 130 revolutions per minute (rpm);

(ii)  $45 \cdot n^{-0.2}$  g/KW-hr ( $34 \cdot n^{-0.2}$  g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and

(iii) 9.8 g/KW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

(2) For engines installed on or after January 1, 2012 and before January 1, 2016, limit the emissions of NO<sub>x</sub> in the stationary CI internal combustion engine exhaust to the following:

(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii)  $44 \cdot n^{-0.23}$  g/KW-hr ( $33 \cdot n^{-0.23}$  g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and

(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

(3) For engines installed on or after January 1, 2016, limit the emissions of NO<sub>x</sub> in the stationary CI internal combustion engine exhaust to the following:

- (i) 3.4 g/KW-hr (2.5 g/HP-hr) when maximum engine speed is less than 130 rpm;
- (ii)  $9.0 \cdot n^{-0.20}$  g/KW-hr ( $6.7 \cdot n^{-0.20}$  g/HP-hr) where n (maximum engine speed) is 130 or more but less than 2,000 rpm; and
- (iii) 2.0 g/KW-hr (1.5 g/HP-hr) where maximum engine speed is greater than or equal to 2,000 rpm.

(4) Reduce particulate matter (PM) emissions by 60 percent or more, or limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.15 g/KW-hr (0.11 g/HP-hr).

(d) Owners and operators of non-emergency stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests in-use must meet the not-to-exceed (NTE) standards as indicated in § 60.4212.

(e) Owners and operators of any modified or reconstructed non-emergency stationary CI ICE subject to this subpart must meet the emission standards applicable to the model year, maximum engine power, and displacement of the modified or reconstructed non-emergency stationary CI ICE that are specified in paragraphs (a) through (d) of this section.

(f) Owners and operators of stationary CI ICE certified to the standards in 40 CFR part 1039 and equipped with AECDs as specified in 40 CFR 1039.665 must meet the Tier 1 certification emission standards for new nonroad CI engines in 40 CFR part 1039, appendix I, while the AECD is activated during a qualified emergency situation. A qualified emergency situation is defined in 40 CFR 1039.665. When the qualified emergency situation has ended and the AECD is deactivated, the engine must resume meeting the otherwise applicable emission standard specified in this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37968, June 28, 2011; 81 FR 44219, July 7, 2016; 86 FR 34358, June 29, 2021]

**§ 60.4205 What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?**

(a) Owners and operators of pre-2007 model year emergency stationary CI ICE with a displacement of less than 10 liters per cylinder that are not fire pump engines must comply with the emission standards in Table 1 to this subpart. Owners and operators of pre-2007 model year emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that are not fire pump engines must comply with the Tier 1 emission standards in 40 CFR part 1042, appendix I.

(b) Owners and operators of 2007 model year and later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards for new nonroad CI engines in § 60.4202, for all pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary CI ICE.

(c) Owners and operators of fire pump engines with a displacement of less than 30 liters per cylinder must comply with the emission standards in table 4 to this subpart, for all pollutants.

(d) Owners and operators of emergency stationary CI engines with a displacement of greater than or equal to 30 liters per cylinder must meet the requirements in this section.

(1) For engines installed prior to January 1, 2012, limit the emissions of NO<sub>x</sub> in the stationary CI internal combustion engine exhaust to the following:

- (i) 17.0 g/KW-hr (12.7 g/HP-hr) when maximum engine speed is less than 130 rpm;
- (ii)  $45 \cdot n^{-0.2}$  g/KW-hr ( $34 \cdot n^{-0.2}$  g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and

(iii) 9.8 g/kW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

(2) For engines installed on or after January 1, 2012, limit the emissions of NO<sub>x</sub> in the stationary CI internal combustion engine exhaust to the following:

(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii)  $44 \cdot n^{-0.23}$  g/KW-hr ( $33 \cdot n^{-0.23}$  g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and

(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

(3) Limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.40 g/KW-hr (0.30 g/HP-hr).

(e) Owners and operators of emergency stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests in-use must meet the NTE standards as indicated in § 60.4212.

(f) Owners and operators of any modified or reconstructed emergency stationary CI ICE subject to this subpart must meet the emission standards applicable to the model year, maximum engine power, and displacement of the modified or reconstructed CI ICE that are specified in paragraphs (a) through (e) of this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011; 86 FR 34358, June 29, 2021]

**§ 60.4206 How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?**

Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in §§ 60.4204 and 60.4205 over the entire life of the engine.

[76 FR 37969, June 28, 2011]

**Fuel Requirements for Owners and Operators**

**§ 60.4207 What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?**

(a) [Reserved]

(b) Beginning October 1, 2010, owners and operators of stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 1090.305 for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to October 1, 2010, may be used until depleted.

(c) [Reserved]

(d) Beginning June 1, 2012, owners and operators of stationary CI ICE subject to this subpart with a displacement of greater than or equal to 30 liters per cylinder must use diesel fuel that meets a maximum per-gallon sulfur content of 1,000 parts per million (ppm).

(e) Stationary CI ICE that have a national security exemption under § 60.4200(d) are also exempt from the fuel requirements in this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011; 78 FR 6695, Jan. 30, 2013; 85 FR 78463, Dec. 4, 2020]

## Other Requirements for Owners and Operators

### **§ 60.4208 What is the deadline for importing or installing stationary CI ICE produced in previous model years?**

- (a) After December 31, 2008, owners and operators may not install stationary CI ICE (excluding fire pump engines) that do not meet the applicable requirements for 2007 model year engines.
- (b) After December 31, 2009, owners and operators may not install stationary CI ICE with a maximum engine power of less than 19 KW (25 HP) (excluding fire pump engines) that do not meet the applicable requirements for 2008 model year engines.
- (c) After December 31, 2014, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 19 KW (25 HP) and less than 56 KW (75 HP) that do not meet the applicable requirements for 2013 model year non-emergency engines.
- (d) After December 31, 2013, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 56 KW (75 HP) and less than 130 KW (175 HP) that do not meet the applicable requirements for 2012 model year non-emergency engines.
- (e) After December 31, 2012, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 130 KW (175 HP), including those above 560 KW (750 HP), that do not meet the applicable requirements for 2011 model year non-emergency engines.
- (f) After December 31, 2016, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 560 KW (750 HP) that do not meet the applicable requirements for 2015 model year non-emergency engines.
- (g) After December 31, 2018, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power greater than or equal to 600 KW (804 HP) and less than 2,000 KW (2,680 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that do not meet the applicable requirements for 2017 model year non-emergency engines.
- (h) In addition to the requirements specified in §§ 60.4201, 60.4202, 60.4204, and 60.4205, it is prohibited to import stationary CI ICE with a displacement of less than 30 liters per cylinder that do not meet the applicable requirements specified in paragraphs (a) through (g) of this section after the dates specified in paragraphs (a) through (g) of this section.
- (i) The requirements of this section do not apply to owners or operators of stationary CI ICE that have been modified, reconstructed, and do not apply to engines that were removed from one existing location and reinstalled at a new location.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

### **§ 60.4209 What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?**

If you are an owner or operator, you must meet the monitoring requirements of this section. In addition, you must also meet the monitoring requirements specified in § 60.4211.

- (a) If you are an owner or operator of an emergency stationary CI internal combustion engine that does not meet the standards applicable to non-emergency engines, you must install a non-resettable hour meter prior to startup of the engine.
- (b) If you are an owner or operator of a stationary CI internal combustion engine equipped with a diesel particulate filter to comply with the emission standards in § 60.4204, the diesel particulate filter must be installed with a

backpressure monitor that notifies the owner or operator when the high backpressure limit of the engine is approached.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

## Compliance Requirements

### § 60.4210 What are my compliance requirements if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their stationary CI ICE with a displacement of less than 10 liters per cylinder to the emission standards specified in §§ 60.4201(a) through (c) and 60.4202(a), (b), and (d) using the certification procedures required in 40 CFR part 1039, subpart C, and must test their engines as specified in 40 CFR part 1039. For the purposes of this subpart, engines certified to the standards in Table 1 to this subpart shall be subject to the same certification procedures required for engines certified to the Tier 1 standards in 40 CFR part 1039, appendix I. For the purposes of this subpart, engines certified to the standards in Table 4 to this subpart shall be subject to the same certification procedures required for engines certified to the Tier 1 standards in 40 CFR part 1039, appendix I, except that engines with NFPA nameplate power of less than 37 KW (50 HP) certified to model year 2011 or later standards shall be subject to the same requirements as engines certified to the standards in 40 CFR part 1039.

(b) Stationary CI internal combustion engine manufacturers must certify their stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder to the emission standards specified in §§ 60.4201(d) and (e) and 60.4202(e) and (f) using the certification procedures required in 40 CFR part 1042, subpart C, and must test their engines as specified in 40 CFR part 1042.

(c) Stationary CI internal combustion engine manufacturers must meet the requirements of 40 CFR 1039.120, 1039.125, 1039.130, and 1039.135 and 40 CFR part 1068 for engines that are certified to the emission standards in 40 CFR part 1039. Stationary CI internal combustion engine manufacturers must meet the corresponding provisions of 40 CFR part 1042 for engines that would be covered by that part if they were nonroad (including marine) engines. Labels on such engines must refer to stationary engines, rather than or in addition to nonroad or marine engines, as appropriate. Stationary CI internal combustion engine manufacturers must label their engines according to paragraphs (c)(1) through (3) of this section.

(1) Stationary CI internal combustion engines manufactured from January 1, 2006 to March 31, 2006 (January 1, 2006 to June 30, 2006 for fire pump engines), other than those that are part of certified engine families under the nonroad CI engine regulations, must be labeled according to 40 CFR 1039.20.

(2) Stationary CI internal combustion engines manufactured from April 1, 2006 to December 31, 2006 (or, for fire pump engines, July 1, 2006 to December 31 of the year preceding the year listed in table 3 to this subpart) must be labeled according to paragraphs (c)(2)(i) through (iii) of this section:

(i) Stationary CI internal combustion engines that are part of certified engine families under the nonroad regulations must meet the labeling requirements for nonroad CI engines, but do not have to meet the labeling requirements in 40 CFR 1039.20.

(ii) Stationary CI internal combustion engines that meet Tier 1 requirements (or requirements for fire pumps) under this subpart, but do not meet the requirements applicable to nonroad CI engines must be labeled according to 40 CFR 1039.20. The engine manufacturer may add language to the label clarifying that the engine meets Tier 1 requirements (or requirements for fire pumps) of this subpart.

(iii) Stationary CI internal combustion engines manufactured after April 1, 2006 that do not meet Tier 1 requirements of this subpart, or fire pumps engines manufactured after July 1, 2006 that do not meet the requirements for fire pumps under this subpart, may not be used in the U.S. If any such engines are manufactured in the U.S. after April 1, 2006 (July 1, 2006 for fire pump engines), they must be exported or must be brought into compliance with the appropriate standards prior to initial operation. The export provisions of 40 CFR 1068.230 would apply to engines for export and the manufacturers must label such engines according to 40 CFR 1068.230.

(3) Stationary CI internal combustion engines manufactured after January 1, 2007 (for fire pump engines, after January 1 of the year listed in table 3 to this subpart, as applicable) must be labeled according to paragraphs (c)(3)(i) through (iii) of this section.

(i) Stationary CI internal combustion engines that meet the requirements of this subpart and the corresponding requirements for nonroad (including marine) engines of the same model year and HP must be labeled according to the provisions in 40 CFR part 1039 or 1042, as appropriate.

(ii) Stationary CI internal combustion engines that meet the requirements of this subpart, but are not certified to the standards applicable to nonroad (including marine) engines of the same model year and HP must be labeled according to the provisions in 40 CFR part 1039 or 1042, as appropriate, but the words "stationary" must be included instead of "nonroad" or "marine" on the label. In addition, such engines must be labeled according to 40 CFR 1039.20.

(iii) Stationary CI internal combustion engines that do not meet the requirements of this subpart must be labeled according to 40 CFR 1068.230 and must be exported under the provisions of 40 CFR 1068.230.

(d) An engine manufacturer certifying an engine family or families to standards under this subpart that are identical to standards applicable under 40 CFR part 1039 or 1042 for that model year may certify any such family that contains both nonroad (including marine) 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.

(e) Manufacturers of engine families discussed in paragraph (d) of this section may meet the labeling requirements referred to in paragraph (c) of this section for stationary CI ICE by either adding a separate label containing the information required in paragraph (c) of this section or by adding the words "and stationary" after the word "nonroad" or "marine," as appropriate, to the label.

(f) Starting with the model years shown in table 5 to this subpart, stationary CI internal combustion engine manufacturers must add a permanent label stating that the engine is for stationary emergency use only to each new emergency stationary CI internal combustion engine greater than or equal to 19 KW (25 HP) that meets all the emission standards for emergency engines in § 60.4202 but does not meet all the emission standards for non-emergency engines in § 60.4201. The label must be added according to the labeling requirements specified in 40 CFR 1039.135(b). Engine manufacturers must specify in the owner's manual that operation of emergency engines is limited to emergency operations and required maintenance and testing.

(g) Manufacturers of fire pump engines may use the test cycle in table 6 to this subpart for testing fire pump engines and may test at the NFPA certified nameplate HP, provided that the engine is labeled as "Fire Pump Applications Only".

(h) Engine manufacturers, including importers, may introduce into commerce uncertified engines or engines certified to earlier standards that were manufactured before the new or changed standards took effect until inventories are depleted, as long as such engines are part of normal inventory. For example, if the engine manufacturers' normal industry practice is to keep on hand a one-month supply of engines based on its projected sales, and a new tier of standards starts to apply for the 2009 model year, the engine manufacturer may manufacture engines based on the normal inventory requirements late in the 2008 model year, and sell those engines for installation. The engine manufacturer may not circumvent the provisions of § 60.4201 or § 60.4202 by stockpiling engines that are built before new or changed standards take effect. Stockpiling of such engines beyond normal industry practice is a violation of this subpart.

(i) The replacement engine provisions of 40 CFR 1068.240 are applicable to stationary CI engines replacing existing equipment that is less than 15 years old.

(j) Stationary CI ICE manufacturers may equip their stationary CI internal combustion engines certified to the emission standards in 40 CFR part 1039 with AECDs for qualified emergency situations according to the requirements of 40 CFR 1039.665. Manufacturers of stationary CI ICE equipped with AECDs as allowed by 40 CFR 1039.665 must meet all the requirements in 40 CFR 1039.665 that apply to manufacturers. Manufacturers must document that the engine complies with the Tier 1 standard in 40 CFR part 1039, appendix I, when the AECD is activated. Manufacturers must provide any relevant testing, engineering analysis, or other information in

sufficient detail to support such statement when applying for certification (including amending an existing certificate) of an engine equipped with an AECD as allowed by 40 CFR 1039.665.

(k) Manufacturers of any size may certify their emergency stationary CI internal combustion engines under this section using assigned deterioration factors established by EPA, consistent with 40 CFR 1039.240 and 1042.240.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011; 81 FR 44219, July 7, 2016; 86 FR 34358, June 29, 2021]

**§ 60.4211 What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?**

(a) If you are an owner or operator and must comply with the emission standards specified in this subpart, you must do all of the following, except as permitted under paragraph (g) of this section:

(1) Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions;

(2) Change only those emission-related settings that are permitted by the manufacturer; and

(3) Meet the requirements of 40 CFR part 1068, as they apply to you.

(b) If you are an owner or operator of a pre-2007 model year stationary CI internal combustion engine and must comply with the emission standards specified in § 60.4204(a) or § 60.4205(a), or if you are an owner or operator of a CI fire pump engine that is manufactured prior to the model years in table 3 to this subpart and must comply with the emission standards specified in § 60.4205(c), you must demonstrate compliance according to one of the methods specified in paragraphs (b)(1) through (5) of this section.

(1) Purchasing an engine certified to emission standards for the same model year and maximum engine power as described in 40 CFR parts 1039 and 1042, as applicable. 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.

(5) Conducting an initial performance test to demonstrate compliance with the emission standards according to the requirements specified in § 60.4212, as applicable.

(c) If you are an owner or operator of a 2007 model year and later stationary CI internal combustion engine and must comply with the emission standards specified in § 60.4204(b) or § 60.4205(b), or if you are an owner or operator of a CI fire pump engine that is manufactured during or after the model year that applies to your fire pump engine power rating in table 3 to this subpart and must comply with the emission standards specified in § 60.4205(c), you must comply by purchasing an engine certified to the emission standards in § 60.4204(b), or § 60.4205(b) or (c), as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. The engine must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in paragraph (g) of this section.

(d) If you are an owner or operator and must comply with the emission standards specified in § 60.4204(c) or § 60.4205(d), you must demonstrate compliance according to the requirements specified in paragraphs (d)(1) through (3) of this section.



(1) Conducting an initial performance test to demonstrate initial compliance with the emission standards as specified in § 60.4213.

(2) Establishing operating parameters to be monitored continuously to ensure the stationary internal combustion engine continues to meet the emission standards. The owner or operator must petition the Administrator for approval of operating parameters to be monitored continuously. The petition must include the information described in paragraphs (d)(2)(i) through (v) of this section.

(i) Identification of the specific parameters you propose to monitor continuously;

(ii) A discussion of the relationship between these parameters and NO<sub>x</sub> and PM emissions, identifying how the emissions of these pollutants change with changes in these parameters, and how limitations on these parameters will serve to limit NO<sub>x</sub> and PM emissions;

(iii) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(iv) A discussion identifying the methods and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(v) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(3) For non-emergency engines with a displacement of greater than or equal to 30 liters per cylinder, conducting annual performance tests to demonstrate continuous compliance with the emission standards as specified in § 60.4213.

(e) If you are an owner or operator of a modified or reconstructed stationary CI internal combustion engine and must comply with the emission standards specified in § 60.4204(e) or § 60.4205(f), you must demonstrate compliance according to one of the methods specified in paragraphs (e)(1) or (2) of this section.

(1) Purchasing, or otherwise owning or operating, an engine certified to the emission standards in § 60.4204(e) or § 60.4205(f), as applicable.

(2) Conducting a performance test to demonstrate initial compliance with the emission standards according to the requirements specified in § 60.4212 or § 60.4213, as appropriate. The test must be conducted within 60 days after the engine commences operation after the modification or reconstruction.

(f) If you own or operate an emergency stationary ICE, you must operate the emergency stationary ICE according to the requirements in paragraphs (f)(1) through (3) of this section. In order for the engine to be considered an emergency stationary ICE under this subpart, any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (3), is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(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 (f)(2)(i) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (f)(3) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the

owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year.

(ii)-(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 (f)(2) of this section. Except as provided in paragraph (f)(3)(i) of this section, the 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator;

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

(ii) [Reserved]

(g) If you do not install, configure, operate, and maintain your engine and control device according to the manufacturer's emission-related written instructions, or you change emission-related settings in a way that is not permitted by the manufacturer, you must demonstrate compliance as follows:

(1) If you are an owner or operator of a stationary CI internal combustion engine with maximum engine power 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. In addition, if you do not install and configure the engine and control device according to the manufacturer's emission-related written instructions, or you change the emission-related settings in a way that is not permitted by the manufacturer, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of such action.

(2) If you are an owner or operator of a stationary CI 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 to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer.

(3) If you are an owner or operator of a stationary CI 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 to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer. You must conduct subsequent performance testing every 8,760 hours of engine operation or 3 years, whichever comes first, thereafter to demonstrate compliance with the applicable emission standards.

(h) The requirements for operators and prohibited acts specified in 40 CFR 1039.665 apply to owners or operators of stationary CI ICE equipped with AECDs for qualified emergency situations as allowed by 40 CFR 1039.665.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37970, June 28, 2011; 78 FR 6695, Jan. 30, 2013; 81 FR 44219, July 7, 2016; 86 FR 34359, June 29, 2021; 87 FR 48605, Aug. 10, 2022]

### Testing Requirements for Owners and Operators

#### **§ 60.4212 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of less than 30 liters per cylinder?**

Owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests pursuant to this subpart must do so according to paragraphs (a) through (e) of this section.

(a) The performance test must be conducted according to the in-use testing procedures in 40 CFR part 1039, subpart F, for stationary CI ICE with a displacement of less than 10 liters per cylinder, and according to 40 CFR part 1042, subpart F, for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder. Alternatively, stationary CI ICE that are complying with Tier 2 or Tier 3 emission standards as described in 40 CFR part 1039, appendix I, or with Tier 2 emission standards as described in 40 CFR part 1042, appendix I, may follow the testing procedures specified in § 60.4213, as appropriate.

(b) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1039 must not exceed the not-to-exceed (NTE) standards for the same model year and maximum engine power as required in 40 CFR 1039.101(e) and 40 CFR 1039.102(g)(1), except as specified in 40 CFR 1039.104(d). This requirement starts when NTE requirements take effect for nonroad diesel engines under 40 CFR part 1039.

(c) Exhaust emissions from stationary CI ICE subject to Tier 2 or Tier 3 emission standards as described in 40 CFR part 1039, appendix I, or Tier 2 emission standards as described in 40 CFR part 1042, appendix I, must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard, determined from the following equation:

$$\text{NTE requirement for each pollutant} = (1.25) \times (\text{STD}) \text{ (Eq. 1)}$$

Where:

STD = The standard specified for that pollutant in 40 CFR part 1039 or 1042, as applicable.

(d) Exhaust emissions from stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in § 60.4204(a), § 60.4205(a), or § 60.4205(c) must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in § 60.4204(a), § 60.4205(a), or § 60.4205(c), determined from the equation in paragraph (c) of this section.

Where:

STD = The standard specified for that pollutant in § 60.4204(a), § 60.4205(a), or § 60.4205(c).

Alternatively, stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in § 60.4204(a), § 60.4205(a), or § 60.4205(c) may follow the testing procedures specified in § 60.4213, as appropriate.

(e) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1042 must not exceed the NTE standards for the same model year and maximum engine power as required in 40 CFR 1042.101(c).

[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011; 86 FR 34359, June 29, 2021]

**§ 60.4213 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of greater than or equal to 30 liters per cylinder?**

Owners and operators of stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder must conduct performance tests according to paragraphs (a) through (f) of this section.

(a) Each performance test must be conducted according to the requirements in § 60.8 and under the specific conditions that this subpart specifies in table 7. The test must be conducted within 10 percent of 100 percent peak (or the highest achievable) load.

(b) You may not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in § 60.8(c).

(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 last at least 1 hour.

(d) To determine compliance with the percent reduction requirement, you must follow the requirements as specified in paragraphs (d)(1) through (3) of this section.

(1) You must use Equation 2 of this section to determine compliance with the percent reduction requirement:

$$\frac{C_i - C_o}{C_i} \times 100 = R \quad (\text{Eq. 2})$$

Where:

$C_i$  = concentration of  $\text{NO}_x$  or PM at the control device inlet,

$C_o$  = concentration of  $\text{NO}_x$  or PM at the control device outlet, and

R = percent reduction of  $\text{NO}_x$  or PM emissions.

(2) You must normalize the  $\text{NO}_x$  or PM concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen ( $\text{O}_2$ ) using Equation 3 of this section, or an equivalent percent carbon dioxide ( $\text{CO}_2$ ) using the procedures described in paragraph (d)(3) of this section.

$$C_{\text{adj}} = C_d \frac{5.9}{20.9 - \% \text{O}_2} \quad (\text{Eq. 3})$$

Where:

$C_{adj}$  = Calculated  $NO_x$  or PM concentration adjusted to 15 percent  $O_2$ .

$C_d$  = Measured concentration of  $NO_x$  or PM, uncorrected.

5.9 = 20.9 percent  $O_2$ –15 percent  $O_2$ , the defined  $O_2$  correction value, percent.

$\%O_2$  = Measured  $O_2$  concentration, dry basis, percent.

(3) If pollutant concentrations are to be corrected to 15 percent  $O_2$  and  $CO_2$  concentration is measured in lieu of  $O_2$  concentration measurement, a  $CO_2$  correction factor is needed. Calculate the  $CO_2$  correction factor as described in paragraphs (d)(3)(i) through (iii) of this section.

(i) Calculate the fuel-specific  $F_o$  value for the fuel burned during the test using values obtained from Method 19, Section 5.2, and the following equation:

$$F_o = \frac{0.209 F_d}{F_c} \quad (\text{Eq. 4})$$

Where:

$F_o$  = Fuel factor based on the ratio of  $O_2$  volume to the ultimate  $CO_2$  volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is  $O_2$ , percent/100.

$F_d$  = Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19,  $dm^3/J$  (dscf/ $10^6$  Btu).

$F_c$  = Ratio of the volume of  $CO_2$  produced to the gross calorific value of the fuel from Method 19,  $dm^3/J$  (dscf/ $10^6$  Btu).

(ii) Calculate the  $CO_2$  correction factor for correcting measurement data to 15 percent  $O_2$ , as follows:

$$X_{CO_2} = \frac{5.9}{F_o} \quad (\text{Eq. 5})$$

Where:

$X_{CO_2}$  =  $CO_2$  correction factor, percent.

5.9 = 20.9 percent  $O_2$ –15 percent  $O_2$ , the defined  $O_2$  correction value, percent.

(iii) Calculate the  $NO_x$  and PM gas concentrations adjusted to 15 percent  $O_2$  using  $CO_2$  as follows:

$$C_{\text{adj}} = C_d \frac{X_{\text{CO}_2}}{\% \text{CO}_2} \quad (\text{Eq. 6})$$

Where:

$C_{\text{adj}}$  = Calculated NO<sub>x</sub> or PM concentration adjusted to 15 percent O<sub>2</sub>.

$C_d$  = Measured concentration of NO<sub>x</sub> or PM, uncorrected.

%CO<sub>2</sub> = Measured CO<sub>2</sub> concentration, dry basis, percent.

(e) To determine compliance with the NO<sub>x</sub> mass per unit output emission limitation, convert the concentration of NO<sub>x</sub> in the engine exhaust using Equation 7 of this section:

$$\text{ER} = \frac{C_d \times 1.912 \times 10^{-3} \times Q \times T}{\text{KW-hour}} \quad (\text{Eq. 7})$$

Where:

ER = Emission rate in grams per KW-hour.

$C_d$  = Measured NO<sub>x</sub> concentration in ppm.

$1.912 \times 10^{-3}$  = Conversion constant for ppm NO<sub>x</sub> to grams per standard cubic meter at 25 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour.

T = Time of test run, in hours.

KW-hour = Brake work of the engine, in KW-hour.

(f) To determine compliance with the PM mass per unit output emission limitation, convert the concentration of PM in the engine exhaust using Equation 8 of this section:

$$\text{ER} = \frac{C_{\text{adj}} \times Q \times T}{\text{KW-hour}} \quad (\text{Eq. 8})$$

Where:

ER = Emission rate in grams per KW-hour.

$C_{\text{adj}}$  = Calculated PM concentration in grams per standard cubic meter.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour.

T = Time of test run, in hours.

KW-hour = Energy output of the engine, in KW.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011]

### **Notification, Reports, and Records for Owners and Operators**

#### **§ 60.4214 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?**

(a) Owners and operators of non-emergency stationary CI ICE that are greater than 2,237 KW (3,000 HP), or have a displacement of greater than or equal to 10 liters per cylinder, or are pre-2007 model year engines that are greater than 130 KW (175 HP) and not certified, must meet the requirements of paragraphs (a)(1) and (2) of this section.

(1) Submit an initial notification as required in § 60.7(a)(1). The notification must include the information in paragraphs (a)(1)(i) through (v) of this section.

(i) Name and address of the owner or operator;

(ii) The address of the affected source;

(iii) Engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement;

(iv) Emission control equipment; and

(v) Fuel used.

(2) Keep records of the information in paragraphs (a)(2)(i) through (iv) of this section.

(i) All notifications submitted to comply with this subpart and all documentation supporting any notification.

(ii) Maintenance conducted on the engine.

(iii) If the stationary CI internal combustion is a certified engine, documentation from the manufacturer that the engine is certified to meet the emission standards.

(iv) If the stationary CI internal combustion is not a certified engine, documentation that the engine meets the emission standards.

(b) If the stationary CI internal combustion engine is an emergency stationary internal combustion engine, the owner or operator is not required to submit an initial notification. Starting with the model years in table 5 to this subpart, if the emergency engine does not meet the standards applicable to non-emergency engines in the applicable model year, the owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time.

(c) If the stationary CI internal combustion engine is equipped with a diesel particulate filter, the owner or operator must keep records of any corrective action taken after the backpressure monitor has notified the owner or operator that the high backpressure limit of the engine is approached.

(d) If you own or operate an emergency stationary CI ICE with a maximum engine power more than 100 HP that operates for the purpose specified in § 60.4211(f)(3)(i), you must submit an annual report according to the requirements in paragraphs (d)(1) through (3) of this section.

(1) The report must contain the following information:

- (i) Company name and address where the engine is located.
- (ii) Date of the report and beginning and ending dates of the reporting period.
- (iii) Engine site rating and model year.
- (iv) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.
- (v)-(vi) [Reserved]
- (vii) Hours spent for operation for the purposes specified in § 60.4211(f)(3)(i), including the date, start time, and end time for engine operation for the purposes specified in § 60.4211(f)(3)(i). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

(2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

(3) The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) ([www.epa.gov/cdx](http://www.epa.gov/cdx)). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in § 60.4.

(e) Owners or operators of stationary CI ICE equipped with AECDs pursuant to the requirements of 40 CFR 1039.665 must report the use of AECDs as required by 40 CFR 1039.665(e).

[71 FR 39172, July 11, 2006, as amended at 78 FR 6696, Jan. 30, 2013; 81 FR 44219, July 7, 2016; 87 FR 48606, Aug. 10, 2022]

### Special Requirements

#### **§ 60.4215 What requirements must I meet for engines used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands?**

(a) Stationary CI ICE with a displacement of less than 30 liters per cylinder that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are required to meet the applicable emission standards in §§ 60.4202 and 60.4205.

(b) Stationary CI ICE that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are not required to meet the fuel requirements in § 60.4207.

(c) Stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are required to meet the following emission standards:

(1) For engines installed prior to January 1, 2012, limit the emissions of NO<sub>x</sub> in the stationary CI internal combustion engine exhaust to the following:

- (i) 17.0 g/KW-hr (12.7 g/HP-hr) when maximum engine speed is less than 130 rpm;
- (ii)  $45 \cdot n^{-0.2}$  g/KW-hr ( $34 \cdot n^{-0.2}$  g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and



(iii) 9.8 g/KW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

(2) For engines installed on or after January 1, 2012, limit the emissions of NO<sub>x</sub> in the stationary CI internal combustion engine exhaust to the following:

(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii)  $44 \cdot n^{-0.23}$  g/KW-hr ( $33 \cdot n^{-0.23}$  g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and

(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

(3) Limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.40 g/KW-hr (0.30 g/HP-hr).

[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011]

#### **§ 60.4216 What requirements must I meet for engines used in Alaska?**

(a) Prior to December 1, 2010, owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder located in areas of Alaska not accessible by the FAHS should refer to 40 CFR part 69 to determine the diesel fuel requirements applicable to such engines.

(b) Except as indicated in paragraph (c) of this section, manufacturers, owners and operators of stationary CI ICE with a displacement of less than 10 liters per cylinder located in remote areas of Alaska may meet the requirements of this subpart by manufacturing and installing engines meeting the Tier 2 or Tier 3 emission standards described in 40 CFR part 1042 for the same model year, displacement, and maximum engine power, as appropriate, rather than the otherwise applicable requirements of 40 CFR part 1039, as indicated in §§ 60.4201(f) and 60.4202(g).

(c) Manufacturers, owners, and operators of stationary CI ICE that are located in remote areas of Alaska may choose to meet the applicable emission standards for emergency engines in §§ 60.4202 and 60.4205, and not those for non-emergency engines in §§ 60.4201 and 60.4204, except that for 2014 model year and later nonemergency CI ICE, the owner or operator of any such engine must have that engine certified as meeting at least the Tier 3 PM standards identified in appendix I of 40 CFR part 1039 or in 40 CFR 1042.101.

(d) The provisions of § 60.4207 do not apply to owners and operators of pre-2014 model year stationary CI ICE subject to this subpart that are located in remote areas of Alaska.

(e) The provisions of § 60.4208(a) do not apply to owners and operators of stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the FAHS until after December 31, 2009.

(f) The provisions of this section and § 60.4207 do not prevent owners and operators of stationary CI ICE subject to this subpart that are located in remote areas of Alaska from using fuels mixed with used lubricating oil, in volumes of up to 1.75 percent of the total fuel. The sulfur content of the used lubricating oil must be less than 200 parts per million. The used lubricating oil must meet the on-specification levels and properties for used oil in 40 CFR 279.11.

[76 FR 37971, June 28, 2011, as amended at 81 FR 44219, July 7, 2016; 86 FR 34359, June 29, 2021]

**§ 60.4217 What emission standards must I meet if I am an owner or operator of a stationary internal combustion engine using special fuels?**

Owners and operators of stationary CI ICE that do not use diesel fuel may petition the Administrator for approval of alternative emission standards, if they can demonstrate that they use a fuel that is not the fuel on which the manufacturer of the engine certified the engine and that the engine cannot meet the applicable standards required in § 60.4204 or § 60.4205 using such fuels and that use of such fuel is appropriate and reasonably necessary, considering cost, energy, technical feasibility, human health and environmental, and other factors, for the operation of the engine.

[76 FR 37972, June 28, 2011]

**General Provisions**

**§ 60.4218 What General Provisions and confidential information provisions apply to me?**

(a) Table 8 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.

[88 FR 4471, Jan. 24, 2023]

**Definitions**

**§ 60.4219 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.

*Alaska Railbelt Grid* means the service areas of the six regulated public utilities that extend from Fairbanks to Anchorage and the Kenai Peninsula. These utilities are Golden Valley Electric Association; Chugach Electric Association; Matanuska Electric Association; Homer Electric Association; Anchorage Municipal Light & Power; and the City of Seward Electric System.

*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 CI ICE with a displacement of less than 10 liters per cylinder are given in 40 CFR 1039.101(g). The values for certified emissions life for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder are given in 40 CFR 1042.101(e).

*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.

*Diesel particulate filter* means an emission control technology that reduces PM emissions by trapping the particles in a flow filter substrate and periodically removes the collected particles by either physical action or by oxidizing (burning off) the particles in a process called regeneration.

*Emergency stationary internal combustion engine* means any stationary reciprocating internal combustion engine that meets all of the criteria in paragraphs (1) through (3) of this definition. All emergency stationary ICE must comply with the requirements specified in § 60.4211(f) in order to be considered emergency stationary ICE. If the engine does not comply with the requirements specified in § 60.4211(f), then it is not considered to be an emergency stationary ICE under this subpart.

- (1) The stationary ICE is operated to provide electrical power or mechanical work during an emergency situation. Examples include stationary ICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary ICE used to pump water in the case of fire or flood, etc.
- (2) The stationary ICE is operated under limited circumstances for situations not included in paragraph (1) of this definition, as specified in § 60.4211(f).
- (3) The stationary ICE operates as part of a financial arrangement with another entity in situations not included in paragraph (1) of this definition only as allowed in § 60.4211(f)(3)(i).

*Engine manufacturer* means the manufacturer of the engine. See the definition of "manufacturer" in this section.

*Fire pump engine* means an emergency stationary internal combustion engine certified to NFPA requirements that is used to provide power to pump water for fire suppression or protection.

*Freshly manufactured engine* means an engine that has not been placed into service. An engine becomes freshly manufactured when it is originally produced.

*Installed* means the engine is placed and secured at the location where it is intended to be operated.

*Manufacturer* has the meaning given in section 216(1) of the 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 sale or resale.

*Maximum engine power* means maximum engine power as defined in 40 CFR 1039.801.

*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”).

*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.

*Reciprocating internal combustion engine* means any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work.

*Remote areas of Alaska* means areas of Alaska that meet either paragraph (1) or (2) of this definition.

- (1) Areas of Alaska that are not accessible by the Federal Aid Highway System (FAHS).
- (2) Areas of Alaska that meet all of the following criteria:
  - (i) The only connection to the FAHS is through the Alaska Marine Highway System, or the stationary CI ICE operation is within an isolated grid in Alaska that is not connected to the statewide electrical grid referred to as the Alaska Railbelt Grid.
  - (ii) At least 10 percent of the power generated by the stationary CI ICE on an annual basis is used for residential purposes.
  - (iii) The generating capacity of the source is less than 12 megawatts, or the stationary CI ICE is used exclusively for backup power for renewable energy.

*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 a gasoline, natural gas, or liquefied petroleum gas fueled engine or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

*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.

*Subpart* means 40 CFR part 60, subpart III.

**Table 1 to Subpart III of Part 60—Emission Standards for Stationary Pre-2007 Model Year Engines With a Displacement of <10 Liters per Cylinder and 2007-2010 Model Year Engines >2,237 KW (3,000 HP) and With a Displacement of <10 Liters per Cylinder**

[As stated in §§60.4201(b), 60.4202(b), 60.4204(a), and 60.4205(a), you must comply with the following emission standards]

Maximum engine power	Emission standards for stationary pre-2007 model year engines with a displacement of <10 liters per cylinder and 2007-2010 model year engines >2,237 KW (3,000 HP) and with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)				
	NMHC + NO <sub>x</sub>	HC	NO <sub>x</sub>	CO	PM
KW<8 (HP<11)	10.5 (7.8)			8.0 (6.0)	1.0 (0.75)
8≤KW<19 (11≤HP<25)	9.5 (7.1)			6.6 (4.9)	0.80 (0.60)
19≤KW<37 (25≤HP<50)	9.5 (7.1)			5.5 (4.1)	0.80 (0.60)
37≤KW<56 (50≤HP<75)			9.2 (6.9)		
56≤KW<75 (75≤HP<100)			9.2 (6.9)		
75≤KW<130 (100≤HP<175)			9.2 (6.9)		
130≤KW<225 (175≤HP<300)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
225≤KW<450 (300≤HP<600)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
450≤KW≤560 (600≤HP≤750)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
KW>560 (HP>750)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)

**Table 2 to Subpart III of Part 60—Emission Standards for 2008 Model Year and Later Emergency Stationary CI ICE <37 KW (50 HP) With a Displacement of <10 Liters per Cylinder**

[As stated in §60.4202(a)(1), you must comply with the following emission standards]

Engine power	Emission standards for 2008 model year and later emergency stationary CI ICE <37 KW (50 HP) with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)			
	Model year(s)	NO <sub>x</sub> + NMHC	CO	PM
KW<8 (HP<11)	2008 +	7.5 (5.6)	8.0 (6.0)	0.40 (0.30)
8≤KW<19 (11≤HP<25)	2008 +	7.5 (5.6)	6.6 (4.9)	0.40 (0.30)
19≤KW<37 (25≤HP<50)	2008 +	7.5 (5.6)	5.5 (4.1)	0.30 (0.22)

**Table 3 to Subpart IIII of Part 60—Certification Requirements for Stationary Fire Pump Engines**

As stated in §60.4202(d), you must certify new stationary fire pump engines beginning with the following model years:

<b>Engine power</b>	<b>Starting model year engine manufacturers must certify new stationary fire pump engines according to §60.4202(d)<sup>1</sup></b>
KW<75 (HP<100)	2011
75≤KW<130 (100≤HP<175)	2010
130≤KW≤560 (175≤HP≤750)	2009
KW>560 (HP>750)	2008

<sup>1</sup>Manufacturers of fire pump stationary CI ICE with a maximum engine power greater than or equal to 37 kW (50 HP) and less than 450 KW (600 HP) and a rated speed of greater than 2,650 revolutions per minute (rpm) are not required to certify such engines until three model years following the model year indicated in this Table 3 for engines in the applicable engine power category.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37972, June 28, 2011]

**Table 4 to Subpart IIII of Part 60—Emission Standards for Stationary Fire Pump Engines**

[As stated in §§60.4202(d) and 60.4205(c), you must comply with the following emission standards for stationary fire pump engines]

<b>Maximum engine power</b>	<b>Model year(s)</b>	<b>NMHC + NO<sub>x</sub></b>	<b>CO</b>	<b>PM</b>
KW<8 (HP<11)	2010 and earlier	10.5 (7.8)	8.0 (6.0)	1.0 (0.75)
	2011 +	7.5 (5.6)		0.40 (0.30)
8≤KW<19 (11≤HP<25)	2010 and earlier	9.5 (7.1)	6.6 (4.9)	0.80 (0.60)
	2011 +	7.5 (5.6)		0.40 (0.30)
19≤KW<37 (25≤HP<50)	2010 and earlier	9.5 (7.1)	5.5 (4.1)	0.80 (0.60)
	2011 +	7.5 (5.6)		0.30 (0.22)
37≤KW<56 (50≤HP<75)	2010 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2011 + <sup>1</sup>	4.7 (3.5)		0.40 (0.30)
56≤KW<75 (75≤HP<100)	2010 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2011 + <sup>1</sup>	4.7 (3.5)		0.40 (0.30)
75≤KW<130 (100≤HP<175)	2009 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2010 + <sup>2</sup>	4.0 (3.0)		0.30 (0.22)
130≤KW<225 (175≤HP<300)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)

Maximum engine power	Model year(s)	NMHC + NO <sub>x</sub>	CO	PM
	2009 + <sup>3</sup>	4.0 (3.0)		0.20 (0.15)
225≤KW<450 (300≤HP<600)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009 + <sup>3</sup>	4.0 (3.0)		0.20 (0.15)
450≤KW≤560 (600≤HP≤750)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009 +	4.0 (3.0)		0.20 (0.15)
KW>560 (HP>750)	2007 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2008 +	6.4 (4.8)		0.20 (0.15)

<sup>1</sup>For model years 2011-2013, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 revolutions per minute (rpm) may comply with the emission limitations for 2010 model year engines.

<sup>2</sup>For model years 2010-2012, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2009 model year engines.

<sup>3</sup>In model years 2009-2011, manufacturers of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2008 model year engines.

**Table 5 to Subpart III of Part 60—Labeling and Recordkeeping Requirements for New Stationary Emergency Engines**

[You must comply with the labeling requirements in §60.4210(f) and the recordkeeping requirements in §60.4214(b) for new emergency stationary CI ICE beginning in the following model years:]

Engine power	Starting model year
19≤KW<56 (25≤HP<75)	2013
56≤KW<130 (75≤HP<175)	2012
KW≥130 (HP≥175)	2011

**Table 6 to Subpart III of Part 60—Optional 3-Mode Test Cycle for Stationary Fire Pump Engines**

[As stated in §60.4210(g), manufacturers of fire pump engines may use the following test cycle for testing fire pump engines:]

Mode No.	Engine speed <sup>1</sup>	Torque (percent) <sup>2</sup>	Weighting factors
1	Rated	100	0.30
2	Rated	75	0.50
3	Rated	50	0.20

<sup>1</sup>Engine speed: ±2 percent of point.

<sup>2</sup>Torque: NFPA certified nameplate HP for 100 percent point. All points should be ±2 percent of engine percent load value.

**Table 7 to Subpart IIII of Part 60—Requirements for Performance Tests for Stationary CI ICE With a Displacement of  $\geq 30$  Liters per Cylinder**

As stated in §60.4213, you must comply with the following requirements for performance tests for stationary CI ICE with a displacement of  $\geq 30$  liters per cylinder:

Each	Complying with the requirement to	You must	Using	According to the following requirements
1. Stationary CI internal combustion engine with a displacement of $\geq 30$ liters per cylinder	a. Reduce NO <sub>x</sub> emissions by 90 percent or more;	i. Select the sampling port location and number/location of traverse points at the inlet and outlet of the control device;		(a) For NO <sub>x</sub> , O <sub>2</sub> , and moisture measurement, ducts $\leq 6$ inches in diameter may be sampled at a single point located at the duct centroid and ducts $> 6$ and $\leq 12$ 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-1, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A-4.
		ii. Measure O <sub>2</sub> at the inlet and outlet of the control device;	(1) Method 3, 3A, or 3B of 40 CFR part 60, appendix A-2	(b) Measurements to determine O <sub>2</sub> concentration must be made at the same time as the measurements for NO <sub>x</sub> concentration.
		iii. If necessary, measure moisture content at the inlet and outlet of the control device; and	(2) Method 4 of 40 CFR part 60, appendix A-3, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see §60.17)	(c) Measurements to determine moisture content must be made at the same time as the measurements for NO <sub>x</sub> concentration.
		iv. Measure NO <sub>x</sub> at the inlet and outlet of the control device.	(3) Method 7E of 40 CFR part 60, appendix A-4, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see §60.17)	(d) NO <sub>x</sub> concentration must be at 15 percent O <sub>2</sub> , dry basis. Results of this test consist of the average of the three 1-hour or longer runs.



Each	Complying with the requirement to	You must	Using	According to the following requirements
	b. Limit the concentration of NO <sub>x</sub> in the stationary CI internal combustion engine exhaust.	i. Select the sampling port location and number/location of traverse points at the exhaust of the stationary internal combustion engine;		(a) For NO <sub>x</sub> , O <sub>2</sub> , 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-1, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A-4.
		ii. Determine the O <sub>2</sub> concentration of the stationary internal combustion engine exhaust at the sampling port location;	(1) Method 3, 3A, or 3B of 40 CFR part 60, appendix A-2	(b) Measurements to determine O <sub>2</sub> concentration must be made at the same time as the measurement for NO <sub>x</sub> concentration.
		iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(2) Method 4 of 40 CFR part 60, appendix A-3, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see §60.17)	(c) Measurements to determine moisture content must be made at the same time as the measurement for NO <sub>x</sub> concentration.
		iv. Measure NO <sub>x</sub> at the exhaust of the stationary internal combustion engine; if using a control device, the sampling site must be located at the outlet of the control device.	(3) Method 7E of 40 CFR part 60, appendix A-4, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see §60.17)	(d) NO <sub>x</sub> concentration must be at 15 percent O <sub>2</sub> , dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
	c. Reduce PM emissions by 60 percent or more	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A-1	(a) Sampling sites must be located at the inlet and outlet of the control device.
		ii. Measure O <sub>2</sub> at the inlet and outlet of the control device;	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A-2	(b) Measurements to determine O <sub>2</sub> concentration must be made at the same time as the measurements for PM concentration.

Each	Complying with the requirement to	You must	Using	According to the following requirements
		iii. If necessary, measure moisture content at the inlet and outlet of the control device; and	(3) Method 4 of 40 CFR part 60, appendix A-3	(c) Measurements to determine and moisture content must be made at the same time as the measurements for PM concentration.
		iv. Measure PM at the inlet and outlet of the control device.	(4) Method 5 of 40 CFR part 60, appendix A-3	(d) PM concentration must be at 15 percent O <sub>2</sub> , dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
	d. Limit the concentration of PM in the stationary CI internal combustion engine exhaust	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A-1	(a) If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O <sub>2</sub> concentration of the stationary internal combustion engine exhaust at the sampling port location;	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A-2	(b) Measurements to determine O <sub>2</sub> concentration must be made at the same time as the measurements for PM concentration.
		iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(3) Method 4 of 40 CFR part 60, appendix A-3	(c) Measurements to determine moisture content must be made at the same time as the measurements for PM concentration.
		iv. Measure PM at the exhaust of the stationary internal combustion engine.	(4) Method 5 of 40 CFR part 60, appendix A-3	(d) PM concentration must be at 15 percent O <sub>2</sub> , dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

[79 FR 11251, Feb. 27, 2014]

**Table 8 to Subpart III of Part 60—Applicability of General Provisions to Subpart III**

[As stated in §60.4218, 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 §60.4219.
§60.3	Units and abbreviations	Yes	
§60.4	Address	Yes	

General Provisions citation	Subject of citation	Applies to subpart	Explanation
§60.5	Determination of construction or modification	Yes	
§60.6	Review of plans	Yes	
§60.7	Notification and Recordkeeping	Yes	Except that §60.7 only applies as specified in §60.4214(a).
§60.8	Performance tests	Yes	Except that §60.8 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder and engines that are not certified.
§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 IIII.
§60.12	Circumvention	Yes	
§60.13	Monitoring requirements	Yes	Except that §60.13 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder.
§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	

## Attachment D

### Part 70 Operating Permit No: 165-47094-00001

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#### Electronic Code of Federal Regulations

#### Title 40: Protection of Environment

#### PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

#### Subpart ZZZZ—National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

SOURCE: 69 FR 33506, June 15, 2004, unless otherwise noted.

#### What This Subpart Covers

#### § 63.6580 What is the purpose of subpart ZZZZ?

Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and operating limitations.

[73 FR 3603, Jan. 18, 2008]

#### § 63.6585 Am I subject to this subpart?

You are subject to this subpart if you own or operate a stationary RICE at a major or area source of HAP emissions, except if the stationary RICE is being tested at a stationary RICE test cell/stand.

(a) A stationary RICE is any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

(b) A major source of HAP emissions is a plant site that emits or has the potential to emit any single HAP at a rate of 10 tons (9.07 megagrams) or more per year or any combination of HAP at a rate of 25 tons (22.68 megagrams) or more per year, except that for oil and gas production facilities, a major source of HAP emissions is determined for each surface site.

(c) An area source of HAP emissions is a source that is not a major source.

(d) If you are an owner or operator of an area source subject to this subpart, your status as an entity subject to a standard or other requirements under this subpart does not subject you to the obligation to obtain a permit under 40 CFR part 70 or 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart as applicable.

(e) If you are an owner or operator of a stationary RICE used for national security purposes, you may be eligible to request an exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C.

(f) The emergency stationary RICE listed in paragraphs (f)(1) through (3) of this section are not subject to this subpart. The stationary RICE must meet the definition of an emergency stationary RICE in § 63.6675, which includes operating according to the provisions specified in § 63.6640(f).

(1) Existing residential emergency stationary RICE located at an area source of HAP emissions that do not operate for the purpose specified in § 63.6640(f)(4)(ii).

(2) Existing commercial emergency stationary RICE located at an area source of HAP emissions that do not operate for the purpose specified in § 63.6640(f)(4)(ii).

(3) Existing institutional emergency stationary RICE located at an area source of HAP emissions that do not operate for the purpose specified in § 63.6640(f)(4)(ii).

[69 FR 33506, June 15, 2004, as amended at 73 FR 3603, Jan. 18, 2008; 78 FR 6700, Jan. 30, 2013; 87 FR 48607, Aug. 10, 2022]

**§ 63.6590 What parts of my plant does this subpart cover?**

This subpart applies to each affected source.

(a) **Affected source.** An affected source is any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions, excluding stationary RICE being tested at a stationary RICE test cell/stand.

**(1) Existing stationary RICE.**

(i) For stationary RICE with a site rating of more than 500 brake horsepower (HP) located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before December 19, 2002.

(ii) For stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iii) For stationary RICE located at an area source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iv) A change in ownership of an existing stationary RICE does not make that stationary RICE a new or reconstructed stationary RICE.

**(2) New stationary RICE.**

(i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

**(3) Reconstructed stationary RICE.**

(i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in § 63.2 and reconstruction is commenced on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in § 63.2 and reconstruction is commenced on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is reconstructed if you meet the definition of reconstruction in § 63.2 and reconstruction is commenced on or after June 12, 2006.

**(b) Stationary RICE subject to limited requirements.**

(1) An affected source which meets either of the criteria in paragraphs (b)(1)(i) through (ii) of this section does not have to meet the requirements of this subpart and of subpart A of this part except for the initial notification requirements of § 63.6645(f).

(i) The stationary RICE is a new or reconstructed emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(ii) The stationary RICE is a new or reconstructed limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(2) A new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis must meet the initial notification requirements of § 63.6645(f) and the requirements of §§ 63.6625(c), 63.6650(g), and 63.6655(c). These stationary RICE do not have to meet the emission limitations and operating limitations of this subpart.

(3) The following stationary RICE do not have to meet the requirements of this subpart and of subpart A of this part, including initial notification requirements:

(i) Existing spark ignition 2 stroke lean burn (2SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(ii) Existing spark ignition 4 stroke lean burn (4SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(iii) Existing emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(iv) Existing limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(v) Existing stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

**(c) Stationary RICE subject to Regulations under 40 CFR Part 60.** An affected source that meets any of the criteria in paragraphs (c)(1) through (7) of this section must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under this part.

(1) A new or reconstructed stationary RICE located at an area source;

(2) A new or reconstructed 2SLB stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(3) A new or reconstructed 4SLB stationary RICE with a site rating of less than 250 brake HP located at a major source of HAP emissions;

(4) A new or reconstructed spark ignition 4 stroke rich burn (4SRB) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(5) A new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

(6) A new or reconstructed emergency or limited use stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(7) A new or reconstructed compression ignition (CI) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3604, Jan. 18, 2008; 75 FR 9674, Mar. 3, 2010; 75 FR 37733, June 30, 2010; 75 FR 51588, Aug. 20, 2010; 78 FR 6700, Jan. 30, 2013; 87 FR 48607, Aug. 10, 2022]

**§ 63.6595 When do I have to comply with this subpart?**

**(a) *Affected sources.***

(1) If you have an existing stationary RICE, excluding existing non-emergency CI stationary RICE, with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the applicable emission limitations, operating limitations and other requirements no later than June 15, 2007. If you have an existing non-emergency CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, an existing stationary CI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary CI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations, operating limitations, and other requirements no later than May 3, 2013. If you have an existing stationary SI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary SI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations, operating limitations, and other requirements no later than October 19, 2013.

(2) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart no later than August 16, 2004.

(3) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions after August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(4) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(5) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(6) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(7) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(b) **Area sources that become major sources.** If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, the compliance dates in paragraphs (b)(1) and (2) of this section apply to you.

(1) Any stationary RICE for which construction or reconstruction is commenced after the date when your area source becomes a major source of HAP must be in compliance with this subpart upon startup of your affected source.

(2) Any stationary RICE for which construction or reconstruction is commenced before your area source becomes a major source of HAP must be in compliance with the provisions of this subpart that are applicable to RICE located at major sources within 3 years after your area source becomes a major source of HAP.

(c) If you own or operate an affected source, you must meet the applicable notification requirements in § 63.6645 and in 40 CFR part 63, subpart A.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3604, Jan. 18, 2008; 75 FR 9675, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010; 78 FR 6701, Jan. 30, 2013]

### **Emission and Operating Limitations**

#### **§ 63.6600 What emission limitations and operating limitations must I meet if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?**

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in § 63.6620 and Table 4 to this subpart.

(a) If you own or operate an existing, new, or reconstructed spark ignition 4SRB stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 1a to this subpart and the operating limitations in Table 1b to this subpart which apply to you.

(b) If you own or operate a new or reconstructed 2SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, a new or reconstructed 4SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, or a new or reconstructed CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

(c) If you own or operate any of the following stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the emission limitations in Tables 1a, 2a, 2c, and 2d to this subpart or operating limitations in Tables 1b and 2b to this subpart: an existing 2SLB stationary RICE; an existing 4SLB stationary RICE; a stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis; an emergency stationary RICE; or a limited use stationary RICE.

(d) If you own or operate an existing non-emergency stationary CI RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2c to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 9675, Mar. 3, 2010]



**§ 63.6601 What emission limitations must I meet if I own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP and less than or equal to 500 brake HP located at a major source of HAP emissions?**

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in § 63.6620 and Table 4 to this subpart. If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at major source of HAP emissions manufactured on or after January 1, 2008, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 9675, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010]

**§ 63.6602 What emission limitations and other requirements must I meet if I own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions?**

If you own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations and other requirements in Table 2c to this subpart which apply to you. Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in § 63.6620 and Table 4 to this subpart.

[78 FR 6701, Jan. 30, 2013]

**§ 63.6603 What emission limitations, operating limitations, and other requirements must I meet if I own or operate an existing stationary RICE located at an area source of HAP emissions?**

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in § 63.6620 and Table 4 to this subpart.

(a) If you own or operate an existing stationary RICE located at an area source of HAP emissions, you must comply with the requirements in Table 2d to this subpart and the operating limitations in Table 2b to this subpart that apply to you.

(b) If you own or operate an existing stationary non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP that meets either paragraph (b)(1) or (2) of this section, you do not have to meet the numerical CO emission limitations specified in Table 2d of this subpart. Existing stationary non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP that meet either paragraph (b)(1) or (2) of this section must meet the management practices that are shown for stationary non-emergency CI RICE with a site rating of less than or equal to 300 HP in Table 2d of this subpart.

(1) The area source is located in an area of Alaska that is not accessible by the Federal Aid Highway System (FAHS).

(2) The stationary RICE is located at an area source that meets paragraphs (b)(2)(i), (ii), and (iii) of this section.

(i) The only connection to the FAHS is through the Alaska Marine Highway System (AMHS), or the stationary RICE operation is within an isolated grid in Alaska that is not connected to the statewide electrical grid referred to as the Alaska Railbelt Grid.

(ii) At least 10 percent of the power generated by the stationary RICE on an annual basis is used for residential purposes.

(iii) The generating capacity of the area source is less than 12 megawatts, or the stationary RICE is used exclusively for backup power for renewable energy.

(c) If you own or operate an existing stationary non-emergency CI RICE with a site rating of more than 300 HP located on an offshore vessel that is an area source of HAP and is a nonroad vehicle that is an Outer Continental Shelf (OCS) source as defined in 40 CFR 55.2, you do not have to meet the numerical CO emission limitations specified in Table 2d of this subpart. You must meet all of the following management practices:

(1) Change oil every 1,000 hours of operation or annually, whichever comes first. Sources have the option to utilize an oil analysis program as described in § 63.6625(i) in order to extend the specified oil change requirement.

(2) Inspect and clean air filters every 750 hours of operation or annually, whichever comes first, and replace as necessary.

(3) Inspect fuel filters and belts, if installed, every 750 hours of operation or annually, whichever comes first, and replace as necessary.

(4) Inspect all flexible hoses every 1,000 hours of operation or annually, whichever comes first, and replace as necessary.

(d) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 1 or Tier 2 emission standards in Table 1 of 40 CFR 89.112 and that is subject to an enforceable state or local standard that requires the engine to be replaced no later than June 1, 2018, you may until January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018, choose to comply with the management practices that are shown for stationary non-emergency CI RICE with a site rating of less than or equal to 300 HP in Table 2d of this subpart instead of the applicable emission limitations in Table 2d, operating limitations in Table 2b, and crankcase ventilation system requirements in § 63.6625(g). You must comply with the emission limitations in Table 2d and operating limitations in Table 2b that apply for non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions by January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018. You must also comply with the crankcase ventilation system requirements in § 63.6625(g) by January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018.

(e) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 3 (Tier 2 for engines above 560 kilowatt (kW)) emission standards in Table 1 of 40 CFR 89.112, you may comply with the requirements under this part by meeting the requirements for Tier 3 engines (Tier 2 for engines above 560 kW) in 40 CFR part 60 subpart IIII instead of the emission limitations and other requirements that would otherwise apply under this part for existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions.

(f) An existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP must meet the definition of remote stationary RICE in § 63.6675 on the initial compliance date for the engine, October 19, 2013, in order to be considered a remote stationary RICE under this subpart. Owners and operators of existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP that meet the definition of remote stationary RICE in § 63.6675 of this subpart as of October 19, 2013 must evaluate the status of their stationary RICE every 12 months. Owners and operators must keep records of the initial and annual evaluation of the status of the engine. If the evaluation indicates that the stationary RICE no longer meets the definition of remote stationary RICE in § 63.6675 of this subpart, the owner or operator must comply with all of the requirements for existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP that are not remote stationary RICE within 1 year of the evaluation.

[75 FR 9675, Mar. 3, 2010, as amended at 75 FR 51589, Aug. 20, 2010; 76 FR 12866, Mar. 9, 2011; 78 FR 6701, Jan. 30, 2013]

**§ 63.6604 What fuel requirements must I meet if I own or operate a stationary CI RICE?**

(a) If you own or operate an existing non-emergency, non-black start CI stationary RICE with a site rating of more than 300 brake HP with a displacement of less than 30 liters per cylinder that uses diesel fuel, you must use diesel fuel that meets the requirements in 40 CFR 1090.305 for nonroad diesel fuel.

(b) Beginning January 1, 2015, if you own or operate an existing emergency CI stationary RICE with a site rating of more than 100 brake HP and a displacement of less than 30 liters per cylinder that uses diesel fuel and operates for the purpose specified in § 63.6640(f)(4)(ii), you must use diesel fuel that meets the requirements in 40 CFR 1090.305 for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to January 1, 2015, may be used until depleted.

(c) [Reserved]

(d) Existing CI stationary RICE located in Guam, American Samoa, the Commonwealth of the Northern Mariana Islands, at area sources in areas of Alaska that meet either § 63.6603(b)(1) or § 63.6603(b)(2), or are on offshore vessels that meet § 63.6603(c) are exempt from the requirements of this section.

[78 FR 6702, Jan. 30, 2013, as amended at 85 FR 78463, Dec. 4, 2020; 87 FR 48607, Aug. 10, 2022]

**General Compliance Requirements**

**§ 63.6605 What are my general requirements for complying with this subpart?**

(a) You must be in compliance with the emission limitations, operating limitations, and other requirements in this subpart that apply to you at all times.

(b) At all times you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require you to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

[75 FR 9675, Mar. 3, 2010, as amended at 78 FR 6702, Jan. 30, 2013]

**Testing and Initial Compliance Requirements**

**§ 63.6610 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?**

If you own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct the initial performance test or other initial compliance demonstrations in Table 4 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in § 63.6595 and according to the provisions in § 63.7(a)(2).

(b) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must demonstrate initial compliance with either the proposed emission limitations or the promulgated emission limitations no later than February 10, 2005 or no later than 180 days after startup of the source, whichever is later, according to § 63.7(a)(2)(ix).

(c) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, and you chose to comply with the proposed emission limitations when demonstrating initial compliance, you must conduct a second performance test to demonstrate compliance with the promulgated emission limitations by December 13, 2007 or after startup of the source, whichever is later, according to § 63.7(a)(2)(ix).

(d) An owner or operator is not required to conduct an initial performance test on units for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (d)(1) through (5) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

(5) The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3605, Jan. 18, 2008]

**§ 63.6611 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a new or reconstructed 4SLB SI stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions?**

If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must conduct an initial performance test within 240 days after the compliance date that is specified for your stationary RICE in § 63.6595 and according to the provisions specified in Table 4 to this subpart, as appropriate.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 51589, Aug. 20, 2010]

**§ 63.6612 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions?**

If you own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct any initial performance test or other initial compliance demonstration according to Tables 4 and 5 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in § 63.6595 and according to the provisions in § 63.7(a)(2).

(b) An owner or operator is not required to conduct an initial performance test on a unit for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (b)(1) through (4) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

[75 FR 9676, Mar. 3, 2010, as amended at 75 FR 51589, Aug. 20, 2010]

**§ 63.6615 When must I conduct subsequent performance tests?**

If you must comply with the emission limitations and operating limitations, you must conduct subsequent performance tests as specified in Table 3 of this subpart.

**§ 63.6620 What performance tests and other procedures must I use?**

(a) You must conduct each performance test in Tables 3 and 4 of this subpart that applies to you.

(b) Each performance test must be conducted according to the requirements that this subpart specifies in Table 4 to this subpart. If you own or operate a non-operational stationary RICE that is subject to performance testing, you do not need to start up the engine solely to conduct the performance test. Owners and operators of a non-operational engine can conduct the performance test when the engine is started up again. The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load for the stationary RICE listed in paragraphs (b)(1) through (4) of this section.

(1) Non-emergency 4SRB stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(2) New non-emergency 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP located at a major source of HAP emissions.

(3) New non-emergency 2SLB stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(4) New non-emergency CI stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(c) [Reserved]

(d) You must conduct three separate test runs for each performance test required in this section, as specified in § 63.7(e)(3). Each test run must last at least 1 hour, unless otherwise specified in this subpart.

(e)

(1) You must use Equation 1 of this section to determine compliance with the percent reduction requirement:

$$\frac{C_i - C_o}{C_i} \times 100 = R \quad (\text{Eq. 1})$$

Where:

C<sub>i</sub> = concentration of carbon monoxide (CO), total hydrocarbons (THC), or formaldehyde at the control device inlet,

$C_o$  = concentration of CO, THC, or formaldehyde at the control device outlet, and

R = percent reduction of CO, THC, or formaldehyde emissions.

(2) You must normalize the CO, THC, or formaldehyde concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen, or an equivalent percent carbon dioxide (CO<sub>2</sub>). If pollutant concentrations are to be corrected to 15 percent oxygen and CO<sub>2</sub> concentration is measured in lieu of oxygen concentration measurement, a CO<sub>2</sub> correction factor is needed. Calculate the CO<sub>2</sub> correction factor as described in paragraphs (e)(2)(i) through (iii) of this section.

(i) Calculate the fuel-specific  $F_o$  value for the fuel burned during the test using values obtained from Method 19, Section 5.2, and the following equation:

$$F_o = \frac{0.209 F_d}{F_c} \quad (\text{Eq. 2})$$

Where:

$F_o$  = Fuel factor based on the ratio of oxygen volume to the ultimate CO<sub>2</sub> volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is oxygen, percent/100.

$F_d$  = Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm<sup>3</sup>/J (dscf/10<sup>6</sup> Btu).

$F_c$  = Ratio of the volume of CO<sub>2</sub> produced to the gross calorific value of the fuel from Method 19, dsm<sup>3</sup>/J (dscf/10<sup>6</sup> Btu)

(ii) Calculate the CO<sub>2</sub> correction factor for correcting measurement data to 15 percent O<sub>2</sub>, as follows:

$$X_{CO_2} = \frac{5.9}{F_o} \quad (\text{Eq. 3})$$

Where:

$X_{CO_2}$  = CO<sub>2</sub> correction factor, percent.

5.9 = 20.9 percent O<sub>2</sub> - 15 percent O<sub>2</sub>, the defined O<sub>2</sub> correction value, percent.

(iii) Calculate the CO, THC, and formaldehyde gas concentrations adjusted to 15 percent O<sub>2</sub> using CO<sub>2</sub> as follows:

$$C_{adj} = C_d \frac{X_{CO_2}}{\%CO_2} \quad (\text{Eq. 4})$$

Where:

$C_{adj}$  = Calculated concentration of CO, THC, or formaldehyde adjusted to 15 percent O<sub>2</sub>.

$C_d$  = Measured concentration of CO, THC, or formaldehyde, uncorrected.

$X_{CO_2}$  = CO<sub>2</sub> correction factor, percent.

%CO<sub>2</sub> = Measured CO<sub>2</sub> concentration measured, dry basis, percent.

(f) If you comply with the emission limitation to reduce CO and you are not using an oxidation catalyst, if you comply with the emission limitation to reduce formaldehyde and you are not using NSCR, or if you comply with the emission limitation to limit the concentration of formaldehyde in the stationary RICE exhaust and you are not using an oxidation catalyst or NSCR, you must petition the Administrator for operating limitations to be established during the initial performance test and continuously monitored thereafter; or for approval of no operating limitations. You must not conduct the initial performance test until after the petition has been approved by the Administrator.

(g) If you petition the Administrator for approval of operating limitations, your petition must include the information described in paragraphs (g)(1) through (5) of this section.

(1) Identification of the specific parameters you propose to use as operating limitations;

(2) A discussion of the relationship between these parameters and HAP emissions, identifying how HAP emissions change with changes in these parameters, and how limitations on these parameters will serve to limit HAP emissions;

(3) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(4) A discussion identifying the methods you will use to measure and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(5) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(h) If you petition the Administrator for approval of no operating limitations, your petition must include the information described in paragraphs (h)(1) through (7) of this section.

(1) Identification of the parameters associated with operation of the stationary RICE and any emission control device which could change intentionally (e.g., operator adjustment, automatic controller adjustment, etc.) or unintentionally (e.g., wear and tear, error, etc.) on a routine basis or over time;

(2) A discussion of the relationship, if any, between changes in the parameters and changes in HAP emissions;

(3) For the parameters which could change in such a way as to increase HAP emissions, a discussion of whether establishing limitations on the parameters would serve to limit HAP emissions;

(4) For the parameters which could change in such a way as to increase HAP emissions, a discussion of how you could establish upper and/or lower values for the parameters which would establish limits on the parameters in operating limitations;

(5) For the parameters, a discussion identifying the methods you could use to measure them and the instruments you could use to monitor them, as well as the relative accuracy and precision of the methods and instruments;

(6) For the parameters, a discussion identifying the frequency and methods for recalibrating the instruments you could use to monitor them; and

(7) A discussion of why, from your point of view, it is infeasible or unreasonable to adopt the parameters as operating limitations.

(i) The engine percent load during a performance test must be determined by documenting the calculations, assumptions, and measurement devices used to measure or estimate the percent load in a specific application. A written report of the average percent load determination must be included in the notification of compliance status. The following information must be included in the written report: the engine model number, the engine manufacturer, the year of purchase, the manufacturer's site-rated brake horsepower, the ambient temperature, pressure, and humidity during the performance test, and all assumptions that were made to estimate or calculate percent load during the performance test must be clearly explained. If measurement devices such as flow meters, kilowatt meters, beta analyzers, stain gauges, etc. are used, the model number of the measurement device, and an estimate of its accurate in percentage of true value must be provided.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9676, Mar. 3, 2010; 78 FR 6702, Jan. 30, 2013]

**§ 63.6625 What are my monitoring, installation, collection, operation, and maintenance requirements?**

(a) If you elect to install a CEMS as specified in Table 5 of this subpart, you must install, operate, and maintain a CEMS to monitor CO and either O<sub>2</sub> or CO<sub>2</sub> according to the requirements in paragraphs (a)(1) through (4) of this section. If you are meeting a requirement to reduce CO emissions, the CEMS must be installed at both the inlet and outlet of the control device. If you are meeting a requirement to limit the concentration of CO, the CEMS must be installed at the outlet of the control device.

(1) Each CEMS must be installed, operated, and maintained according to the applicable performance specifications of 40 CFR part 60, appendix B.

(2) You must conduct an initial performance evaluation and an annual relative accuracy test audit (RATA) of each CEMS according to the requirements in § 63.8 and according to the applicable performance specifications of 40 CFR part 60, appendix B as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.

(3) As specified in § 63.8(c)(4)(ii), each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. You must have at least two data points, with each representing a different 15-minute period, to have a valid hour of data.

(4) The CEMS data must be reduced as specified in § 63.8(g)(2) and recorded in parts per million or parts per billion (as appropriate for the applicable limitation) at 15 percent oxygen or the equivalent CO<sub>2</sub> concentration.

(b) If you are required to install a continuous parameter monitoring system (CPMS) as specified in Table 5 of this subpart, you must install, operate, and maintain each CPMS according to the requirements in paragraphs (b)(1) through (6) of this section. For an affected source that is complying with the emission limitations and operating limitations on March 9, 2011, the requirements in paragraph (b) of this section are applicable September 6, 2011.

(1) You must prepare a site-specific monitoring plan that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraphs (b)(1)(i) through (v) of this section and in § 63.8(d). As specified in § 63.8(f)(4), you may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in paragraphs (b)(1) through (5) of this section in your site-specific monitoring plan.

(i) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations;

(ii) Sampling interface (e.g., thermocouple) location such that the monitoring system will provide representative measurements;

(iii) Equipment performance evaluations, system accuracy audits, or other audit procedures;



(iv) Ongoing operation and maintenance procedures in accordance with provisions in § 63.8(c)(1)(ii) and (c)(3); and

(v) Ongoing reporting and recordkeeping procedures in accordance with provisions in § 63.10(c), (e)(1), and (e)(2)(i).

(2) You must install, operate, and maintain each CPMS in continuous operation according to the procedures in your site-specific monitoring plan.

(3) The CPMS must collect data at least once every 15 minutes (see also § 63.6635).

(4) For a CPMS for measuring temperature range, the temperature sensor must have a minimum tolerance of 2.8 degrees Celsius (5 degrees Fahrenheit) or 1 percent of the measurement range, whichever is larger.

(5) You must conduct the CPMS equipment performance evaluation, system accuracy audits, or other audit procedures specified in your site-specific monitoring plan at least annually.

(6) You must conduct a performance evaluation of each CPMS in accordance with your site-specific monitoring plan.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must monitor and record your fuel usage daily with separate fuel meters to measure the volumetric flow rate of each fuel. In addition, you must operate your stationary RICE in a manner which reasonably minimizes HAP emissions.

(d) If you are operating a new or reconstructed emergency 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must install a non-resettable hour meter prior to the startup of the engine.

(e) If you own or operate any of the following stationary RICE, you must operate and maintain the stationary RICE and after-treatment control device (if any) according to the manufacturer's emission-related written instructions or develop your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions:

(1) An existing stationary RICE with a site rating of less than 100 HP located at a major source of HAP emissions;

(2) An existing emergency or black start stationary RICE with a site rating of less than or equal to 500 HP located at a major source of HAP emissions;

(3) An existing emergency or black start stationary RICE located at an area source of HAP emissions;

(4) An existing non-emergency, non-black start stationary CI RICE with a site rating less than or equal to 300 HP located at an area source of HAP emissions;

(5) An existing non-emergency, non-black start 2SLB stationary RICE located at an area source of HAP emissions;

(6) An existing non-emergency, non-black start stationary RICE located at an area source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis.

(7) An existing non-emergency, non-black start 4SLB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(8) An existing non-emergency, non-black start 4SRB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(9) An existing, non-emergency, non-black start 4SLB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year; and

(10) An existing, non-emergency, non-black start 4SRB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year.

(f) If you own or operate an existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing emergency stationary RICE located at an area source of HAP emissions, you must install a non-resettable hour meter if one is not already installed.

(g) If you own or operate an existing non-emergency, non-black start CI engine greater than or equal to 300 HP that is not equipped with a closed crankcase ventilation system, you must comply with either paragraph (g)(1) or paragraph (2) of this section. Owners and operators must follow the manufacturer's specified maintenance requirements for operating and maintaining the open or closed crankcase ventilation systems and replacing the crankcase filters, or can request the Administrator to approve different maintenance requirements that are as protective as manufacturer requirements. Existing CI engines located at area sources in areas of Alaska that meet either § 63.6603(b)(1) or § 63.6603(b)(2) do not have to meet the requirements of this paragraph (g). Existing CI engines located on offshore vessels that meet § 63.6603(c) do not have to meet the requirements of this paragraph (g).

(1) Install a closed crankcase ventilation system that prevents crankcase emissions from being emitted to the atmosphere, or

(2) Install an open crankcase filtration emission control system that reduces emissions from the crankcase by filtering the exhaust stream to remove oil mist, particulates and metals.

(h) If you operate a new, reconstructed, or existing stationary engine, you must minimize the engine's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the emission standards applicable to all times other than startup in Tables 1a, 2a, 2c, and 2d to this subpart apply.

(i) If you own or operate a stationary CI engine that is subject to the work, operation or management practices in items 1 or 2 of Table 2c to this subpart or in items 1 or 4 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Base Number is less than 30 percent of the Total Base Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

(j) If you own or operate a stationary SI engine that is subject to the work, operation or management practices in items 6, 7, or 8 of Table 2c to this subpart or in items 5, 6, 7, 9, or 11 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Acid Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Acid Number increases by more than 3.0 milligrams of potassium hydroxide (KOH) per gram from Total Acid Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not

exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3606, Jan. 18, 2008; 75 FR 9676, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010; 76 FR 12866, Mar. 9, 2011; 78 FR 6703, Jan. 30, 2013]

**§ 63.6630 How do I demonstrate initial compliance with the emission limitations, operating limitations, and other requirements?**

- (a) You must demonstrate initial compliance with each emission limitation, operating limitation, and other requirement that applies to you according to Table 5 of this subpart.
- (b) During the initial performance test, you must establish each operating limitation in Tables 1b and 2b of this subpart that applies to you.
- (c) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in § 63.6645.
- (d) Non-emergency 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions by 76 percent or more can demonstrate initial compliance with the formaldehyde emission limit by testing for THC instead of formaldehyde. The testing must be conducted according to the requirements in Table 4 of this subpart. The average reduction of emissions of THC determined from the performance test must be equal to or greater than 30 percent.
- (e) The initial compliance demonstration required for existing non-emergency 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year must be conducted according to the following requirements:
  - (1) The compliance demonstration must consist of at least three test runs.
  - (2) Each test run must be of at least 15 minute duration, except that each test conducted using the method in appendix A to this subpart must consist of at least one measurement cycle and include at least 2 minutes of test data phase measurement.
  - (3) If you are demonstrating compliance with the CO concentration or CO percent reduction requirement, you must measure CO emissions using one of the CO measurement methods specified in Table 4 of this subpart, or using appendix A to this subpart.
  - (4) If you are demonstrating compliance with the THC percent reduction requirement, you must measure THC emissions using Method 25A, reported as propane, of 40 CFR part 60, appendix A.
  - (5) You must measure O<sub>2</sub> using one of the O<sub>2</sub> measurement methods specified in Table 4 of this subpart. Measurements to determine O<sub>2</sub> concentration must be made at the same time as the measurements for CO or THC concentration.
  - (6) If you are demonstrating compliance with the CO or THC percent reduction requirement, you must measure CO or THC emissions and O<sub>2</sub> emissions simultaneously at the inlet and outlet of the control device.

[69 FR 33506, June 15, 2004, as amended at 78 FR 6704, Jan. 30, 2013]

## Continuous Compliance Requirements

### § 63.6635 How do I monitor and collect data to demonstrate continuous compliance?

- (a) If you must comply with emission and operating limitations, you must monitor and collect data according to this section.
- (b) Except for monitor malfunctions, associated repairs, required performance evaluations, and required quality assurance or control activities, you must monitor continuously at all times that the stationary RICE is operating. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.
- (c) You may not use data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities in data averages and calculations used to report emission or operating levels. You must, however, use all the valid data collected during all other periods.

[69 FR 33506, June 15, 2004, as amended at 76 FR 12867, Mar. 9, 2011]

### § 63.6640 How do I demonstrate continuous compliance with the emission limitations, operating limitations, and other requirements?

- (a) You must demonstrate continuous compliance with each emission limitation, operating limitation, and other requirements in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you according to methods specified in Table 6 to this subpart.
- (b) You must report each instance in which you did not meet each emission limitation or operating limitation in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you. These instances are deviations from the emission and operating limitations in this subpart. These deviations must be reported according to the requirements in § 63.6650. If you change your catalyst, you must reestablish the values of the operating parameters measured during the initial performance test. When you reestablish the values of your operating parameters, you must also conduct a performance test to demonstrate that you are meeting the required emission limitation applicable to your stationary RICE.
- (c) The annual compliance demonstration required for existing non-emergency 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year must be conducted according to the following requirements:
  - (1) The compliance demonstration must consist of at least one test run.
  - (2) Each test run must be of at least 15 minute duration, except that each test conducted using the method in appendix A to this subpart must consist of at least one measurement cycle and include at least 2 minutes of test data phase measurement.
  - (3) If you are demonstrating compliance with the CO concentration or CO percent reduction requirement, you must measure CO emissions using one of the CO measurement methods specified in Table 4 of this subpart, or using appendix A to this subpart.
  - (4) If you are demonstrating compliance with the THC percent reduction requirement, you must measure THC emissions using Method 25A, reported as propane, of 40 CFR part 60, appendix A.
  - (5) You must measure O<sub>2</sub> using one of the O<sub>2</sub> measurement methods specified in Table 4 of this subpart. Measurements to determine O<sub>2</sub> concentration must be made at the same time as the measurements for CO or THC concentration.

(6) If you are demonstrating compliance with the CO or THC percent reduction requirement, you must measure CO or THC emissions and O<sub>2</sub> emissions simultaneously at the inlet and outlet of the control device.

(7) If the results of the annual compliance demonstration show that the emissions exceed the levels specified in Table 6 of this subpart, the stationary RICE must be shut down as soon as safely possible, and appropriate corrective action must be taken (e.g., repairs, catalyst cleaning, catalyst replacement). The stationary RICE must be retested within 7 days of being restarted and the emissions must meet the levels specified in Table 6 of this subpart. If the retest shows that the emissions continue to exceed the specified levels, the stationary RICE must again be shut down as soon as safely possible, and the stationary RICE may not operate, except for purposes of startup and testing, until the owner/operator demonstrates through testing that the emissions do not exceed the levels specified in Table 6 of this subpart.

(d) For new, reconstructed, and rebuilt stationary RICE, deviations from the emission or operating limitations that occur during the first 200 hours of operation from engine startup (engine burn-in period) are not violations. Rebuilt stationary RICE means a stationary RICE that has been rebuilt as that term is defined in 40 CFR 94.11(a).

(e) You must also report each instance in which you did not meet the requirements in Table 8 to this subpart that apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing emergency stationary RICE, an existing limited use stationary RICE, or an existing stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart, except for the initial notification requirements: a new or reconstructed stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new or reconstructed emergency stationary RICE, or a new or reconstructed limited use stationary RICE.

(f) If you own or operate an emergency stationary RICE, you must operate the emergency stationary RICE according to the requirements in paragraphs (f)(1) through (4) of this section. In order for the engine to be considered an emergency stationary RICE under this subpart, any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (4), is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (4), the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary RICE in emergency situations.

(2) You may operate your emergency stationary RICE for the purpose specified in paragraph (f)(2)(i) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraphs (f)(3) and (4) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary RICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year.

(ii)-(iii) [Reserved]

(3) Emergency stationary RICE located at major sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing provided in paragraph (f)(2) of this

section. The 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(4) Emergency stationary RICE located at area sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing provided in paragraph (f)(2) of this section. Except as provided in paragraphs (f)(4)(i) and (ii) of this section, the 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) Prior to May 3, 2014, the 50 hours per year for non-emergency situations can be used for peak shaving or non-emergency demand response to generate income for a facility, or to otherwise supply power as part of a financial arrangement with another entity if the engine is operated as part of a peak shaving (load management program) with the local distribution system operator and the power is provided only to the facility itself or to support the local distribution system.

(ii) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator.

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

[69 FR 33506, June 15, 2004, as amended at 71 FR 20467, Apr. 20, 2006; 73 FR 3606, Jan. 18, 2008; 75 FR 9676, Mar. 3, 2010; 75 FR 51591, Aug. 20, 2010; 78 FR 6704, Jan. 30, 2013; 87 FR 48607, Aug. 10, 2022]

## **Notifications, Reports, and Records**

### **§ 63.6645 What notifications must I submit and when?**

(a) You must submit all of the notifications in §§ 63.7(b) and (c), 63.8(e), (f)(4) and (f)(6), 63.9(b) through (e), and (g) and (h) that apply to you by the dates specified if you own or operate any of the following;

(1) An existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

(2) An existing stationary RICE located at an area source of HAP emissions.

(3) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(4) A new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 HP located at a major source of HAP emissions.

(5) This requirement does not apply if you own or operate an existing stationary RICE less than 100 HP, an existing stationary emergency RICE, or an existing stationary RICE that is not subject to any numerical emission standards.

(b) As specified in § 63.9(b)(2), if you start up your stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart, you must submit an Initial Notification not later than December 13, 2004, or no later than 120 days after the source becomes subject to this subpart, whichever is later.

(c) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions on or after August 16, 2004, you must submit an Initial Notification not later than 120 days after you become subject to this subpart.

(d) As specified in § 63.9(b)(2), if you start up your stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart and you are required to submit an initial notification, you must submit an Initial Notification not later than July 16, 2008, or no later than 120 days after the source becomes subject to this subpart, whichever is later.

(e) If you start up your new or reconstructed stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions on or after March 18, 2008 and you are required to submit an initial notification, you must submit an Initial Notification not later than 120 days after you become subject to this subpart.

(f) If you are required to submit an Initial Notification but are otherwise not affected by the requirements of this subpart, in accordance with § 63.6590(b), your notification should include the information in § 63.9(b)(2)(i) through (v), and a statement that your stationary RICE has no additional requirements and explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary RICE if it has a site rating of more than 500 brake HP located at a major source of HAP emissions).

(g) If you are required to conduct a performance test, you must submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin as required in § 63.7(b)(1).

(h) If you are required to conduct a performance test or other initial compliance demonstration as specified in Tables 4 and 5 to this subpart, you must submit a Notification of Compliance Status according to § 63.9(h)(2)(ii).

(1) For each initial compliance demonstration required in Table 5 to this subpart that does not include a performance test, you must submit the Notification of Compliance Status before the close of business on the 30th day following the completion of the initial compliance demonstration.

(2) For each initial compliance demonstration required in Table 5 to this subpart that includes a performance test conducted according to the requirements in Table 3 to this subpart, you must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th day following the completion of the performance test according to § 63.10(d)(2).

(i) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 1 or Tier 2 emission standards in Table 1 of 40 CFR 89.112 and subject to an enforceable state or local standard requiring engine replacement and you intend to meet management practices rather than emission limits, as specified in § 63.6603(d), you must submit a notification by March 3, 2013, stating that you intend to use the provision in § 63.6603(d) and identifying the state or local regulation that the engine is subject to.

**§ 63.6650 What reports must I submit and when?**

(a) You must submit each report in Table 7 of this subpart that applies to you.

(b) Unless the Administrator has approved a different schedule for submission of reports under § 63.10(a), you must submit each report by the date in Table 7 of this subpart and according to the requirements in paragraphs (b)(1) through (b)(9) of this section.

(1) For semiannual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in § 63.6595 and ending on June 30 or December 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in § 63.6595.

(2) For semiannual Compliance reports, the first Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date follows the end of the first calendar half after the compliance date that is specified for your affected source in § 63.6595.

(3) For semiannual Compliance reports, each subsequent Compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) For semiannual Compliance reports, each subsequent Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(5) For each stationary RICE that is subject to permitting regulations pursuant to 40 CFR part 70 or 71, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6 (a)(3)(iii)(A), you may submit the first and subsequent Compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (b)(4) of this section.

(6) For annual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in § 63.6595 and ending on December 31.

(7) For annual Compliance reports, the first Compliance report must be postmarked or delivered no later than January 31 following the end of the first calendar year after the compliance date that is specified for your affected source in § 63.6595.

(8) For annual Compliance reports, each subsequent Compliance report must cover the annual reporting period from January 1 through December 31.

(9) For annual Compliance reports, each subsequent Compliance report must be postmarked or delivered no later than January 31.

(c) The Compliance report must contain the information in paragraphs (c)(1) through (6) of this section.

(1) Company name and address.

(2) Statement by a responsible official, with that official's name, title, and signature, certifying the accuracy of the content of the report.

(3) Date of report and beginning and ending dates of the reporting period.

(4) If you had a malfunction during the reporting period, the compliance report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a



description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with § 63.6605(b), including actions taken to correct a malfunction.

(5) If there are no deviations from any emission or operating limitations that apply to you, a statement that there were no deviations from the emission or operating limitations during the reporting period.

(6) If there were no periods during which the continuous monitoring system (CMS), including CEMS and CPMS, was out-of-control, as specified in § 63.8(c)(7), a statement that there were no periods during which the CMS was out-of-control during the reporting period.

(d) For each deviation from an emission or operating limitation that occurs for a stationary RICE where you are not using a CMS to comply with the emission or operating limitations in this subpart, the Compliance report must contain the information in paragraphs (c)(1) through (4) of this section and the information in paragraphs (d)(1) and (2) of this section.

(1) The total operating time of the stationary RICE at which the deviation occurred during the reporting period.

(2) Information on the number, duration, and cause of deviations (including unknown cause, if applicable), as applicable, and the corrective action taken.

(e) For each deviation from an emission or operating limitation occurring for a stationary RICE where you are using a CMS to comply with the emission and operating limitations in this subpart, you must include information in paragraphs (c)(1) through (4) and (e)(1) through (12) of this section.

(1) The date and time that each malfunction started and stopped.

(2) The date, time, and duration that each CMS was inoperative, except for zero (low-level) and high-level checks.

(3) The date, time, and duration that each CMS was out-of-control, including the information in § 63.8(c)(8).

(4) The date and time that each deviation started and stopped, and whether each deviation occurred during a period of malfunction or during another period.

(5) A summary of the total duration of the deviation during the reporting period, and the total duration as a percent of the total source operating time during that reporting period.

(6) A breakdown of the total duration of the deviations during the reporting period into those that are due to control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of CMS downtime during the reporting period, and the total duration of CMS downtime as a percent of the total operating time of the stationary RICE at which the CMS downtime occurred during that reporting period.

(8) An identification of each parameter and pollutant (CO or formaldehyde) that was monitored at the stationary RICE.

(9) A brief description of the stationary RICE.

(10) A brief description of the CMS.

(11) The date of the latest CMS certification or audit.

(12) A description of any changes in CMS, processes, or controls since the last reporting period.

(f) Each affected source that has obtained a title V operating permit pursuant to 40 CFR part 70 or 71 must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6 (a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a Compliance report pursuant to Table 7 of this subpart along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the Compliance report includes all required information concerning deviations from any emission or operating limitation in this subpart, submission of the Compliance report shall be deemed to satisfy any obligation to report the same deviations in the semiannual monitoring report. However, submission of a Compliance report shall not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.

(g) If you are operating as a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must submit an annual report according to Table 7 of this subpart by the date specified unless the Administrator has approved a different schedule, according to the information described in paragraphs (b)(1) through (b)(5) of this section. You must report the data specified in (g)(1) through (g)(3) of this section.

(1) Fuel flow rate of each fuel and the heating values that were used in your calculations. You must also demonstrate that the percentage of heat input provided by landfill gas or digester gas is equivalent to 10 percent or more of the total fuel consumption on an annual basis.

(2) The operating limits provided in your federally enforceable permit, and any deviations from these limits.

(3) Any problems or errors suspected with the meters.

(h) If you own or operate an emergency stationary RICE with a site rating of more than 100 brake HP that operates for the purpose specified in § 63.6640(f)(4)(ii), you must submit an annual report according to the requirements in paragraphs (h)(1) through (3) of this section.

(1) The report must contain the following information:

(i) Company name and address where the engine is located.

(ii) Date of the report and beginning and ending dates of the reporting period.

(iii) Engine site rating and model year.

(iv) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(v)-(vi) {Reserved}

(vii) Hours spent for operation for the purpose specified in § 63.6640(f)(4)(ii), including the date, start time, and end time for engine operation for the purposes specified in § 63.6640(f)(4)(ii). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

(viii) If there were no deviations from the fuel requirements in § 63.6604 that apply to the engine (if any), a statement that there were no deviations from the fuel requirements during the reporting period.

(ix) If there were deviations from the fuel requirements in § 63.6604 that apply to the engine (if any), information on the number, duration, and cause of deviations, and the corrective action taken.

(2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

(3) The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data

Exchange (CDX) ([www.epa.gov/cdx](http://www.epa.gov/cdx)). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in § 63.13.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9677, Mar. 3, 2010; 78 FR 6705, Jan. 30, 2013; 87 FR 48607, Aug. 10, 2022]

### § 63.6655 What records must I keep?

(a) If you must comply with the emission and operating limitations, you must keep the records described in paragraphs (a)(1) through (a)(5), (b)(1) through (b)(3) and (c) of this section.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status that you submitted, according to the requirement in § 63.10(b)(2)(xiv).

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

(3) Records of performance tests and performance evaluations as required in § 63.10(b)(2)(viii).

(4) Records of all required maintenance performed on the air pollution control and monitoring equipment.

(5) Records of actions taken during periods of malfunction to minimize emissions in accordance with § 63.6605(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(b) For each CEMS or CPMS, you must keep the records listed in paragraphs (b)(1) through (3) of this section.

(1) Records described in § 63.10(b)(2)(vi) through (xi).

(2) Previous (*i.e.*, superseded) versions of the performance evaluation plan as required in § 63.8(d)(3).

(3) Requests for alternatives to the relative accuracy test for CEMS or CPMS as required in § 63.8(f)(6)(i), if applicable.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must keep the records of your daily fuel usage monitors.

(d) You must keep the records required in Table 6 of this subpart to show continuous compliance with each emission or operating limitation that applies to you.

(e) You must keep records of the maintenance conducted on the stationary RICE in order to demonstrate that you operated and maintained the stationary RICE and after-treatment control device (if any) according to your own maintenance plan if you own or operate any of the following stationary RICE;

(1) An existing stationary RICE with a site rating of less than 100 brake HP located at a major source of HAP emissions.

(2) An existing stationary emergency RICE.

(3) An existing stationary RICE located at an area source of HAP emissions subject to management practices as shown in Table 2d to this subpart.

(f) If you own or operate any of the stationary RICE in paragraphs (f)(1) through (2) of this section, you must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The owner or operator must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation. If the engine is used for the purpose specified in § 63.6640(f)(4)(ii), the owner or operator must keep records of the notification of the emergency situation, and the date, start time, and end time of engine operation for these purposes.

(1) An existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions that does not meet the standards applicable to non-emergency engines.

(2) An existing emergency stationary RICE located at an area source of HAP emissions that does not meet the standards applicable to non-emergency engines.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9678, Mar. 3, 2010; 75 FR 51592, Aug. 20, 2010; 78 FR 6706, Jan. 30, 2013; 87 FR 48607, Aug. 10, 2022]

**§ 63.6660 In what form and how long must I keep my records?**

(a) Your records must be in a form suitable and readily available for expeditious review according to § 63.10(b)(1).

(b) As specified in § 63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 63.10(b)(1).

[69 FR 33506, June 15, 2004, as amended at 75 FR 9678, Mar. 3, 2010]

**Other Requirements and Information**

**§ 63.6665 What parts of the General Provisions apply to me?**

Table 8 to this subpart shows which parts of the General Provisions in §§ 63.1 through 63.15 apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with any of the requirements of the General Provisions specified in Table 8: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing stationary RICE that combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, an existing emergency stationary RICE, or an existing limited use stationary RICE. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in the General Provisions specified in Table 8 except for the initial notification requirements: A new stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new emergency stationary RICE, or a new limited use stationary RICE.

[75 FR 9678, Mar. 3, 2010]

**§ 63.6670 Who implements and enforces this subpart?**

(a) This subpart is implemented and enforced by the U.S. EPA, or a delegated authority such as your State, local, or tribal agency. If the U.S. EPA Administrator has delegated authority to your State, local, or tribal agency, then that agency (as well as the U.S. EPA) has the authority to implement and enforce this subpart. You should contact your U.S. EPA Regional Office to find out whether this subpart is delegated to your State, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under 40 CFR part 63, subpart E, the authorities contained in paragraph (c) of this section are retained by the Administrator of the U.S. EPA and are not transferred to the State, local, or tribal agency.

(c) The authorities that will not be delegated to State, local, or tribal agencies are:

(1) Approval of alternatives to the non-opacity emission limitations and operating limitations in § 63.6600 under § 63.6(g).

(2) Approval of major alternatives to test methods under § 63.7(e)(2)(ii) and (f) and as defined in § 63.90.

(3) Approval of major alternatives to monitoring under § 63.8(f) and as defined in § 63.90.

(4) Approval of major alternatives to recordkeeping and reporting under § 63.10(f) and as defined in § 63.90.

(5) Approval of a performance test which was conducted prior to the effective date of the rule, as specified in § 63.6610(b).

**§ 63.6675 What definitions apply to this subpart?**

Terms used in this subpart are defined in the Clean Air Act (CAA); in 40 CFR 63.2, the General Provisions of this part; and in this section as follows:

*Alaska Railbelt Grid* means the service areas of the six regulated public utilities that extend from Fairbanks to Anchorage and the Kenai Peninsula. These utilities are Golden Valley Electric Association; Chugach Electric Association; Matanuska Electric Association; Homer Electric Association; Anchorage Municipal Light & Power; and the City of Seward Electric System.

*Area source* means any stationary source of HAP that is not a major source as defined in part 63.

*Associated equipment* as used in this subpart and as referred to in section 112(n)(4) of the CAA, means equipment associated with an oil or natural gas exploration or production well, and includes all equipment from the well bore to the point of custody transfer, except glycol dehydration units, storage vessels with potential for flash emissions, combustion turbines, and stationary RICE.

*Backup power for renewable energy* means an engine that provides backup power to a facility that generates electricity from renewable energy resources, as that term is defined in Alaska Statute 42.45.045(l)(5) (incorporated by reference, see § 63.14).

*Black start engine* means an engine whose only purpose is to start up a combustion turbine.

*CAA* means the Clean Air Act (42 U.S.C. 7401 *et seq.*, as amended by Public Law 101-549, 104 Stat. 2399).

*Commercial emergency stationary RICE* means an emergency stationary RICE used in commercial establishments such as office buildings, hotels, stores, telecommunications facilities, restaurants, financial institutions such as banks, doctor's offices, and sports and performing arts facilities.

*Compression ignition* means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

*Custody transfer* means the transfer of hydrocarbon liquids or natural gas: After processing and/or treatment in the producing operations, or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation. For the purposes of this subpart, the point at which such liquids or natural gas enters a natural gas processing plant is a point of custody transfer.

*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 limitation or operating limitation;
- (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 limitation or operating limitation in this subpart during malfunction, regardless or whether or not such failure is permitted by this subpart.
- (4) Fails to satisfy the general duty to minimize emissions established by § 63.6(e)(1)(i).

*Diesel engine* means any stationary RICE in which a high boiling point liquid fuel injected into the combustion chamber ignites when the air charge has been compressed to a temperature sufficiently high for auto-ignition. This process is also known as compression ignition.

*Diesel fuel* means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is fuel oil number 2. Diesel fuel also includes any non-distillate fuel with comparable physical and chemical properties (e.g. biodiesel) that is suitable for use in compression ignition engines.

*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 CO<sub>2</sub>.

*Dual-fuel engine* means any stationary RICE 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.

*Emergency stationary RICE* means any stationary reciprocating internal combustion engine that meets all of the criteria in paragraphs (1) through (3) of this definition. All emergency stationary RICE must comply with the requirements specified in § 63.6640(f) in order to be considered emergency stationary RICE. If the engine does not comply with the requirements specified in § 63.6640(f), then it is not considered to be an emergency stationary RICE under this subpart.

- (1) The stationary RICE is operated to provide electrical power or mechanical work during an emergency situation. Examples include stationary RICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary RICE used to pump water in the case of fire or flood, etc.
- (2) The stationary RICE is operated under limited circumstances for situations not included in paragraph (1) of this definition, as specified in § 63.6640(f).
- (3) The stationary RICE operates as part of a financial arrangement with another entity in situations not included in paragraph (1) of this definition only as allowed in § 63.6640(f)(4)(i) or (ii).

*Engine startup* means the time from initial start until applied load and engine and associated equipment reaches steady state or normal operation. For stationary engine with catalytic controls, engine startup means the time from initial start until applied load and engine and associated equipment, including the catalyst, reaches steady state or normal operation.

*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.

*Gaseous fuel* means a material used for combustion which is in the gaseous state at standard atmospheric temperature and pressure conditions.

*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.

*Glycol dehydration unit* means a device in which a liquid glycol (including, but not limited to, ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water in a contact tower or absorption column (absorber). The glycol contacts and absorbs water vapor and other gas stream constituents from the natural gas and becomes "rich" glycol. This glycol is then regenerated in the glycol dehydration unit reboiler. The "lean" glycol is then recycled.

*Hazardous air pollutants (HAP)* means any air pollutants listed in or pursuant to section 112(b) of the CAA.

*Institutional emergency stationary RICE* means an emergency stationary RICE used in institutional establishments such as medical centers, nursing homes, research centers, institutions of higher education, correctional facilities, elementary and secondary schools, libraries, religious establishments, police stations, and fire stations.

*ISO standard day conditions* means 288 degrees Kelvin (15 degrees Celsius), 60 percent relative humidity and 101.3 kilopascals pressure.

*Landfill gas* means a gaseous by-product of the land application of municipal refuse typically formed through the anaerobic decomposition of waste materials and composed principally of methane and CO<sub>2</sub>.

*Lean burn engine* means any two-stroke or four-stroke spark ignited engine that does not meet the definition of a rich burn engine.

*Limited use stationary RICE* means any stationary RICE that operates less than 100 hours per year.

*Liquefied petroleum gas* means any liquefied hydrocarbon gas obtained as a by-product in petroleum refining of natural gas production.

*Liquid fuel* means any fuel in liquid form at standard temperature and pressure, including but not limited to diesel, residual/crude oil, kerosene/naphtha (jet fuel), and gasoline.

*Major Source*, as used in this subpart, shall have the same meaning as in § 63.2, except that:

- (1) Emissions from any oil or gas exploration or production well (with its associated equipment (as defined in this section)) and emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units, to determine whether such emission points or stations are major sources, even when emission points are in a contiguous area or under common control;
- (2) For oil and gas production facilities, emissions from processes, operations, or equipment that are not part of the same oil and gas production facility, as defined in § 63.1271 of subpart HHH of this part, shall not be aggregated;
- (3) For production field facilities, only HAP emissions from glycol dehydration units, storage vessel with the potential for flash emissions, combustion turbines and reciprocating internal combustion engines shall be aggregated for a major source determination; and
- (4) Emissions from processes, operations, and equipment that are not part of the same natural gas transmission and storage facility, as defined in § 63.1271 of subpart HHH of this part, shall not be aggregated.

*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 which causes, or has the potential to cause, the emission limitations in an applicable standard to be exceeded. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

*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.

*Non-selective catalytic reduction (NSCR)* means an add-on catalytic nitrogen oxides (NO<sub>x</sub>) control device for rich burn engines that, in a two-step reaction, promotes the conversion of excess oxygen, NO<sub>x</sub>, CO, and volatile organic compounds (VOC) into CO<sub>2</sub>, nitrogen, and water.

*Oil and gas production facility* as used in this subpart means any grouping of equipment where hydrocarbon liquids are processed, upgraded (*i.e.*, remove impurities or other constituents to meet contract specifications), or stored prior to the point of custody transfer; or where natural gas is processed, upgraded, or stored prior to entering the natural gas transmission and storage source category. For purposes of a major source determination, facility (including a building, structure, or installation) means oil and natural gas production and processing equipment that is located within the boundaries of an individual surface site as defined in this section. Equipment that is part of a facility will typically be located within close proximity to other equipment located at the same facility. Pieces of production equipment or groupings of equipment located on different oil and gas leases, mineral fee tracts, lease tracts, subsurface or surface unit areas, surface fee tracts, surface lease tracts, or separate surface sites, whether or not connected by a road, waterway, power line or pipeline, shall not be considered part of the same facility. Examples of facilities in the oil and natural gas production source category include, but are not limited to, well sites, satellite tank batteries, central tank batteries, a compressor station that transports natural gas to a natural gas processing plant, and natural gas processing plants.

*Oxidation catalyst* means an add-on catalytic control device that controls CO and VOC by oxidation.

*Peaking unit or engine* means any standby engine intended for use during periods of high demand that are not emergencies.

*Percent load* means the fractional power of an engine compared to its maximum manufacturer's design capacity at engine site conditions. Percent load may range between 0 percent to above 100 percent.

*Potential to emit* means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the stationary source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. For oil and natural gas production facilities subject to subpart HH of this part, the potential to emit provisions in § 63.760(a) may be used. For natural gas transmission and storage facilities subject to subpart HHH of this part, the maximum annual facility gas throughput for storage facilities may be determined according to § 63.1270(a)(1) and the maximum annual throughput for transmission facilities may be determined according to § 63.1270(a)(2).

*Production field facility* means those oil and gas production facilities located prior to the point of custody transfer.

*Production well* means any hole drilled in the earth from which crude oil, condensate, or field natural gas is extracted.

*Propane* means a colorless gas derived from petroleum and natural gas, with the molecular structure C<sub>3</sub>H<sub>8</sub>.

*Remote stationary RICE* means stationary RICE meeting any of the following criteria:

- (1) Stationary RICE located in an offshore area that is beyond the line of ordinary low water along that portion of the coast of the United States that is in direct contact with the open seas and beyond the line marking the seaward limit of inland waters.



(2) Stationary RICE located on a pipeline segment that meets both of the criteria in paragraphs (2)(i) and (ii) of this definition.

(i) A pipeline segment with 10 or fewer buildings intended for human occupancy and no buildings with four or more stories within 220 yards (200 meters) on either side of the centerline of any continuous 1-mile (1.6 kilometers) length of pipeline. Each separate dwelling unit in a multiple dwelling unit building is counted as a separate building intended for human occupancy.

(ii) The pipeline segment does not lie within 100 yards (91 meters) of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. The days and weeks need not be consecutive. The building or area is considered occupied for a full day if it is occupied for any portion of the day.

(iii) For purposes of this paragraph (2), the term pipeline segment means all parts of those physical facilities through which gas moves in transportation, including but not limited to pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies. Stationary RICE located within 50 yards (46 meters) of the pipeline segment providing power for equipment on a pipeline segment are part of the pipeline segment. Transportation of gas means the gathering, transmission, or distribution of gas by pipeline, or the storage of gas. A building is intended for human occupancy if its primary use is for a purpose involving the presence of humans.

(3) Stationary RICE that are not located on gas pipelines and that have 5 or fewer buildings intended for human occupancy and no buildings with four or more stories within a 0.25 mile radius around the engine. A building is intended for human occupancy if its primary use is for a purpose involving the presence of humans.

*Residential emergency stationary RICE* means an emergency stationary RICE used in residential establishments such as homes or apartment buildings.

*Responsible official* means responsible official as defined in 40 CFR 70.2.

*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 December 19, 2002 with passive emission control technology for NO<sub>x</sub> (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.

*Site-rated HP* means the maximum manufacturer's design capacity at engine site conditions.

*Spark ignition* means relating to either: A gasoline-fueled engine; or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

*Stationary reciprocating internal combustion engine (RICE)* means any reciprocating internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

*Stationary RICE test cell/stand* means an engine test cell/stand, as defined in subpart PPPPP of this part, that tests stationary RICE.

*Stoichiometric* means the theoretical air-to-fuel ratio required for complete combustion.

*Storage vessel with the potential for flash emissions* means any storage vessel that contains a hydrocarbon liquid with a stock tank gas-to-oil ratio equal to or greater than 0.31 cubic meters per liter and an American Petroleum Institute gravity equal to or greater than 40 degrees and an actual annual average hydrocarbon liquid throughput equal to or greater than 79,500 liters per day. Flash emissions occur when dissolved hydrocarbons in the fluid evolve from solution when the fluid pressure is reduced.

*Subpart* means 40 CFR part 63, subpart ZZZZ.

*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.

*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.

[69 FR 33506, June 15, 2004, as amended at 71 FR 20467, Apr. 20, 2006; 73 FR 3607, Jan. 18, 2008; 75 FR 9679, Mar. 3, 2010; 75 FR 51592, Aug. 20, 2010; 76 FR 12867, Mar. 9, 2011; 78 FR 6706, Jan. 30, 2013; 87 FR 48608, Aug. 10, 2022]

**Table 1a to Subpart ZZZZ of Part 63—Emission Limitations for Existing, New, and Reconstructed Spark Ignition, 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions**

As stated in §§63.6600 and 63.6640, you must comply with the following emission limitations at 100 percent load plus or minus 10 percent for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions:

For each . . .	You must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .
1. 4SRB stationary RICE	a. Reduce formaldehyde emissions by 76 percent or more. If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may reduce formaldehyde emissions by 75 percent or more until June 15, 2007 or	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply. <sup>1</sup>
	b. Limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O <sub>2</sub>	

<sup>1</sup> Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[75 FR 9679, Mar. 3, 2010, as amended at 75 FR 51592, Aug. 20, 2010]

**Table 1b to Subpart ZZZZ of Part 63—Operating Limitations for Existing, New, and Reconstructed SI 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions**

As stated in §§63.6600, 63.6603, 63.6630 and 63.6640, you must comply with the following operating limitations for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions:

For each . . .	You must meet the following operating limitation, except during periods of startup . . .
1. existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and using NSCR; or existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O <sub>2</sub> and using NSCR;	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst measured during the initial performance test; and b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 750 °F and less than or equal to 1250 °F. <sup>1</sup>
2. existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and not using NSCR; or	Comply with any operating limitations approved by the Administrator.
existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O <sub>2</sub> and not using NSCR.	

<sup>1</sup>Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(f) for a different temperature range.

[78 FR 6706, Jan. 30, 2013]

**Table 2a to Subpart ZZZZ of Part 63—Emission Limitations for New and Reconstructed 2SLB and Compression Ignition Stationary RICE >500 HP and New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions**

As stated in §§63.6600 and 63.6640, you must comply with the following emission limitations for new and reconstructed lean burn and new and reconstructed compression ignition stationary RICE at 100 percent load plus or minus 10 percent:

For each . . .	You must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .
1. 2SLB stationary RICE	a. Reduce CO emissions by 58 percent or more; or b. Limit concentration of formaldehyde in the stationary RICE exhaust to 12 ppmvd or less at 15 percent O <sub>2</sub> . If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may limit concentration of formaldehyde to 17 ppmvd or less at 15 percent O <sub>2</sub> until June 15, 2007	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply. <sup>1</sup>
2. 4SLB stationary RICE	a. Reduce CO emissions by 93 percent or more; or	

For each . . .	You must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .
	b. Limit concentration of formaldehyde in the stationary RICE exhaust to 14 ppmvd or less at 15 percent O <sub>2</sub>	
3. CI stationary RICE	a. Reduce CO emissions by 70 percent or more; or	
	b. Limit concentration of formaldehyde in the stationary RICE exhaust to 580 ppbvd or less at 15 percent O <sub>2</sub>	

<sup>1</sup>Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[75 FR 9680, Mar. 3, 2010]

**Table 2b to Subpart ZZZZ of Part 63—Operating Limitations for New and Reconstructed 2SLB and CI Stationary RICE >500 HP Located at a Major Source of HAP Emissions, New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions, Existing CI Stationary RICE >500 HP**

As stated in §§63.6600, 63.6601, 63.6603, 63.6630, and 63.6640, you must comply with the following operating limitations for new and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions; new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions; and existing CI stationary RICE >500 HP:

For each . . .	You must meet the following operating limitation, except during periods of startup . . .
1. New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to reduce CO emissions and using an oxidation catalyst; and New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and using an oxidation catalyst.	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst that was measured during the initial performance test; and b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450 °F and less than or equal to 1350 °F. <sup>1</sup>
2. Existing CI stationary RICE >500 HP complying with the requirement to limit or reduce the concentration of CO in the stationary RICE exhaust and using an oxidation catalyst	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water from the pressure drop across the catalyst that was measured during the initial performance test; and b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450 °F and less than or equal to 1350 °F. <sup>1</sup>
3. New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to reduce CO emissions and not using an oxidation catalyst; and	Comply with any operating limitations approved by the Administrator.

For each . . .	You must meet the following operating limitation, except during periods of startup . . .
New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and not using an oxidation catalyst; and	
existing CI stationary RICE >500 HP complying with the requirement to limit or reduce the concentration of CO in the stationary RICE exhaust and not using an oxidation catalyst.	

<sup>1</sup>Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(f) for a different temperature range.

[78 FR 6707, Jan. 30, 2013]

**Table 2c to Subpart ZZZZ of Part 63—Requirements for Existing Compression Ignition Stationary RICE Located at a Major Source of HAP Emissions and Existing Spark Ignition Stationary RICE ≤500 HP Located at a Major Source of HAP Emissions**

As stated in §§63.6600, 63.6602, and 63.6640, you must comply with the following requirements for existing compression ignition stationary RICE located at a major source of HAP emissions and existing spark ignition stationary RICE ≤500 HP located at a major source of HAP emissions:

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Emergency stationary CI RICE and black start stationary CI RICE <sup>1</sup>	a. Change oil and filter every 500 hours of operation or annually, whichever comes first. <sup>2</sup> b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary. <sup>3</sup>	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply. <sup>3</sup>

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
2. Non-Emergency, non-black start stationary CI RICE <100 HP	<p>a. Change oil and filter every 1,000 hours of operation or annually, whichever comes first.<sup>2</sup></p> <p>b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary;</p> <p>c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.<sup>3</sup></p>	
3. Non-Emergency, non-black start CI stationary RICE 100≤HP≤300 HP	Limit concentration of CO in the stationary RICE exhaust to 230 ppmvd or less at 15 percent O <sub>2</sub> .	
4. Non-Emergency, non-black start CI stationary RICE 300<HP≤500	<p>a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd or less at 15 percent O<sub>2</sub>; or</p> <p>b. Reduce CO emissions by 70 percent or more.</p>	
5. Non-Emergency, non-black start stationary CI RICE >500 HP	<p>a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd or less at 15 percent O<sub>2</sub>; or</p> <p>b. Reduce CO emissions by 70 percent or more.</p>	
6. Emergency stationary SI RICE and black start stationary SI RICE. <sup>1</sup>	<p>a. Change oil and filter every 500 hours of operation or annually, whichever comes first;<sup>2</sup></p> <p>b. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first, and replace as necessary;</p> <p>c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.<sup>3</sup></p>	
7. Non-Emergency, non-black start stationary SI RICE <100 HP that are not 2SLB stationary RICE	<p>a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;<sup>2</sup></p> <p>b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary;</p>	

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary. <sup>3</sup>	
8. Non-Emergency, non-black start 2SLB stationary SI RICE <100 HP	a. Change oil and filter every 4,320 hours of operation or annually, whichever comes first; <sup>2</sup> b. Inspect spark plugs every 4,320 hours of operation or annually, whichever comes first, and replace as necessary;	
	c. Inspect all hoses and belts every 4,320 hours of operation or annually, whichever comes first, and replace as necessary. <sup>3</sup>	
9. Non-emergency, non-black start 2SLB stationary RICE 100≤HP≤500	Limit concentration of CO in the stationary RICE exhaust to 225 ppmvd or less at 15 percent O <sub>2</sub> .	
10. Non-emergency, non-black start 4SLB stationary RICE 100≤HP≤500	Limit concentration of CO in the stationary RICE exhaust to 47 ppmvd or less at 15 percent O <sub>2</sub> .	
11. Non-emergency, non-black start 4SRB stationary RICE 100≤HP≤500	Limit concentration of formaldehyde in the stationary RICE exhaust to 10.3 ppmvd or less at 15 percent O <sub>2</sub> .	
12. Non-emergency, non-black start stationary RICE 100≤HP≤500 which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	Limit concentration of CO in the stationary RICE exhaust to 177 ppmvd or less at 15 percent O <sub>2</sub> .	

<sup>1</sup>If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the work practice requirements on the schedule required in Table 2c of this subpart, or if performing the work practice on the required schedule would otherwise pose an unacceptable risk under federal, state, or local law, the work practice can be delayed until the emergency is over or the unacceptable risk under federal, state, or local law has abated. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under federal, state, or local law has abated. Sources must report any failure to perform the work practice on the schedule required and the federal, state or local law under which the risk was deemed unacceptable.

<sup>2</sup>Sources have the option to utilize an oil analysis program as described in §63.6625(i) or (j) in order to extend the specified oil change requirement in Table 2c of this subpart.

<sup>3</sup>Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[78 FR 6708, Jan. 30, 2013, as amended at 78 FR 14457, Mar. 6, 2013]

**Table 2d to Subpart ZZZZ of Part 63—Requirements for Existing Stationary RICE Located at Area Sources of HAP Emissions**

As stated in §§63.6603 and 63.6640, you must comply with the following requirements for existing stationary RICE located at area sources of HAP emissions:

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Non-Emergency, non-black start CI stationary RICE ≤300 HP	a. Change oil and filter every 1,000 hours of operation or annually, whichever comes first; <sup>1</sup> b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.
2. Non-Emergency, non-black start CI stationary RICE 300<HP≤500	a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd at 15 percent O <sub>2</sub> ; or	
	b. Reduce CO emissions by 70 percent or more.	
3. Non-Emergency, non-black start CI stationary RICE >500 HP	a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd at 15 percent O <sub>2</sub> ; or	
	b. Reduce CO emissions by 70 percent or more.	
4. Emergency stationary CI RICE and black start stationary CI RICE. <sup>2</sup>	a. Change oil and filter every 500 hours of operation or annually, whichever comes first; <sup>1</sup>	
	b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	



For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
5. Emergency stationary SI RICE; black start stationary SI RICE; non-emergency, non-black start 4SLB stationary RICE >500 HP that operate 24 hours or less per calendar year; non-emergency, non-black start 4SRB stationary RICE >500 HP that operate 24 hours or less per calendar year. <sup>2</sup>	a. Change oil and filter every 500 hours of operation or annually, whichever comes first; <sup>1</sup> b. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; and c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	
6. Non-emergency, non-black start 2SLB stationary RICE	a. Change oil and filter every 4,320 hours of operation or annually, whichever comes first; <sup>1</sup>	
	b. Inspect spark plugs every 4,320 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 4,320 hours of operation or annually, whichever comes first, and replace as necessary.	
7. Non-emergency, non-black start 4SLB stationary RICE ≤500 HP	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first; <sup>1</sup>	
	b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	
8. Non-emergency, non-black start 4SLB remote stationary RICE >500 HP	a. Change oil and filter every 2,160 hours of operation or annually, whichever comes first; <sup>1</sup>	
	b. Inspect spark plugs every 2,160 hours of operation or annually, whichever comes first, and replace as necessary; and	

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
	c. Inspect all hoses and belts every 2,160 hours of operation or annually, whichever comes first, and replace as necessary.	
9. Non-emergency, non-black start 4SLB stationary RICE >500 HP that are not remote stationary RICE and that operate more than 24 hours per calendar year	Install an oxidation catalyst to reduce HAP emissions from the stationary RICE.	
10. Non-emergency, non-black start 4SRB stationary RICE ≤500 HP	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first; <sup>1</sup>	
	b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	
11. Non-emergency, non-black start 4SRB remote stationary RICE >500 HP	a. Change oil and filter every 2,160 hours of operation or annually, whichever comes first; <sup>1</sup>	
	b. Inspect spark plugs every 2,160 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 2,160 hours of operation or annually, whichever comes first, and replace as necessary.	
12. Non-emergency, non-black start 4SRB stationary RICE >500 HP that are not remote stationary RICE and that operate more than 24 hours per calendar year	Install NSCR to reduce HAP emissions from the stationary RICE.	
13. Non-emergency, non-black start stationary RICE which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first; <sup>1</sup> b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; and	

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	

<sup>1</sup>Sources have the option to utilize an oil analysis program as described in §63.6625(i) or (j) in order to extend the specified oil change requirement in Table 2d of this subpart.

<sup>2</sup>If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the management practice requirements on the schedule required in Table 2d of this subpart, or if performing the management practice on the required schedule would otherwise pose an unacceptable risk under federal, state, or local law, the management practice can be delayed until the emergency is over or the unacceptable risk under federal, state, or local law has abated. The management practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under federal, state, or local law has abated. Sources must report any failure to perform the management practice on the schedule required and the federal, state or local law under which the risk was deemed unacceptable.

[78 FR 6709, Jan. 30, 2013]

**Table 3 to Subpart ZZZZ of Part 63—Subsequent Performance Tests**

As stated in §§63.6615 and 63.6620, you must comply with the following subsequent performance test requirements:

For each . . .	Complying with the requirement to . . .	You must . . .
1. New or reconstructed 2SLB stationary RICE >500 HP located at major sources; new or reconstructed 4SLB stationary RICE ≥250 HP located at major sources; and new or reconstructed CI stationary RICE >500 HP located at major sources	Reduce CO emissions and not using a CEMS	Conduct subsequent performance tests semiannually. <sup>1</sup>
2. 4SRB stationary RICE ≥5,000 HP located at major sources	Reduce formaldehyde emissions	Conduct subsequent performance tests semiannually. <sup>1</sup>
3. Stationary RICE >500 HP located at major sources and new or reconstructed 4SLB stationary RICE 250≤HP≤500 located at major sources	Limit the concentration of formaldehyde in the stationary RICE exhaust	Conduct subsequent performance tests semiannually. <sup>1</sup>
4. Existing non-emergency, non-black start CI stationary RICE >500 HP that are not limited use stationary RICE	Limit or reduce CO emissions and not using a CEMS	Conduct subsequent performance tests every 8,760 hours or 3 years, whichever comes first.
5. Existing non-emergency, non-black start CI stationary RICE >500 HP that are limited use stationary RICE	Limit or reduce CO emissions and not using a CEMS	Conduct subsequent performance tests every 8,760 hours or 5 years, whichever comes first.

<sup>1</sup>After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

[78 FR 6711, Jan. 30, 2013]

**Table 4 to Subpart ZZZZ of Part 63—Requirements for Performance Tests**

As stated in §§ 63.6610, 63.6611, 63.6620, and 63.6640, you must comply with the following requirements for performance tests for stationary RICE:

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
1. 2SLB, 4SLB, and CI stationary RICE	a. Reduce CO emissions	i. Select the sampling port location and the number/location of traverse points at the inlet and outlet of the control device; and		(a) For CO, O <sub>2</sub> , 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–1, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification testing and select sampling points according to section 8.1.2 of method 7E of 40 CFR part 60, appendix A–4.
		ii. Measure the O <sub>2</sub> at the inlet and outlet of the control device; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A–2, or ASTM D6522–00 (Reapproved 2005) <sup>13</sup> (heated probe not necessary)	(b) Measurements to determine O <sub>2</sub> must be made at the same time as the measurements for CO concentration.
		iii. Measure the CO at the inlet and the outlet of the control device; and	(2) ASTM D6522–00 (Reapproved 2005) <sup>123</sup> (heated probe not necessary) or method 10 of 40 CFR part 60, appendix A–4	(c) The CO concentration must be at 15 percent O <sub>2</sub> , dry basis.
		iv. Measure moisture content at the inlet and outlet of the control device as needed to determine CO and O <sub>2</sub> concentrations on a dry basis	(3) Method 4 of 40 CFR part 60, appendix A–3, or method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03 <sup>13</sup>	(d) Measurements to determine moisture content must be made at the same time and location as the measurements for CO concentration.

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
2. 4SRB stationary RICE	a. Reduce formaldehyde or THC emissions	i. Select the sampling port location and the number/location of traverse points at the inlet and outlet of the control device; and		(a) For formaldehyde, THC, O <sub>2</sub> , 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. Measure O <sub>2</sub> at the inlet and outlet of the control device; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A–2, or ASTM D6522–00 (Reapproved 2005) <sup>13</sup> (heated probe not necessary)	(b) Measurements to determine O <sub>2</sub> concentration must be made at the same time as the measurements for formaldehyde or THC concentration.
		iii. Measure moisture content at the inlet and outlet of the control device as needed to determine formaldehyde or THC and O <sub>2</sub> concentrations on a dry basis; and	(2) Method 4 of 40 CFR part 60, appendix A–3, or method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03 <sup>13</sup>	(c) Measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde or THC concentration.
		iv. If demonstrating compliance with the formaldehyde percent reduction requirement, measure formaldehyde at the inlet and the outlet of the control device	(3) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348–03, <sup>13</sup> provided in ASTM D6348–03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130	(d) Formaldehyde concentration must be at 15 percent O <sub>2</sub> , dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
		v. If demonstrating compliance with the THC percent reduction requirement, measure THC at the inlet and the outlet of the control device	(4) (1) Method 25A, reported as propane, of 40 CFR part 60, appendix A–7	(e) THC concentration must be at 15 percent O <sub>2</sub> , dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
3. Stationary RICE	a. Limit the concentration of formaldehyde or CO in the stationary RICE exhaust	i. Select the sampling port location and the number/location of traverse points at the exhaust of the stationary RICE; and		(a) For formaldehyde, CO, O <sub>2</sub> , 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. If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O <sub>2</sub> concentration of the stationary RICE exhaust at the sampling port location; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A–2, or ASTM D6522–00 (Reapproved 2005) <sup>13</sup> (heated probe not necessary)	(b) Measurements to determine O <sub>2</sub> concentration must be made at the same time and location as the measurements for formaldehyde or CO concentration.
		iii. Measure moisture content of the stationary RICE exhaust at the sampling port location as needed to determine formaldehyde or CO and O <sub>2</sub> concentrations on a dry basis; and	(2) Method 4 of 40 CFR part 60, appendix A–3, or method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03 <sup>13</sup>	(c) Measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde or CO concentration.

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
		iv. Measure formaldehyde at the exhaust of the stationary RICE; or	(3) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348–03, <sup>13</sup> provided in ASTM D6348–03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130	(d) Formaldehyde concentration must be at 15 percent O <sub>2</sub> , dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
		v. Measure CO at the exhaust of the stationary RICE	(4) Method 10 of 40 CFR part 60, appendix A–4, ASTM D6522–00 (2005), <sup>13</sup> method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03 <sup>13</sup>	(e) CO concentration must be at 15 percent O <sub>2</sub> , dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

<sup>1</sup> You may also use methods 3A and 10 as options to ASTM–D6522–00 (2005).

<sup>2</sup> You may obtain a copy of ASTM–D6348–03 from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428–2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.

<sup>3</sup> Incorporated by reference, see § 63.14.

[88 FR 18413, Mar. 29, 2023]

**Table 5 to Subpart ZZZZ of Part 63—Initial Compliance With Emission Limitations, Operating Limitations, and Other Requirements**

As stated in §§63.6612, 63.6625 and 63.6630, you must initially comply with the emission and operating limitations as required by the following:

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
1. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Reduce CO emissions and using oxidation catalyst, and using a CPMS	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
2. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Limit the concentration of CO, using oxidation catalyst, and using a CPMS	i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Reduce CO emissions and not using oxidation catalyst	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.
4. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Limit the concentration of CO, and not using oxidation catalyst	i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
5. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Reduce CO emissions, and using a CEMS	i. You have installed a CEMS to continuously monitor CO and either O <sub>2</sub> or CO <sub>2</sub> at both the inlet and outlet of the oxidation catalyst according to the requirements in §63.6625(a); and ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and
		iii. The average reduction of CO calculated using §63.6620 equals or exceeds the required percent reduction. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average percent reduction achieved during the 4-hour period.
6. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Limit the concentration of CO, and using a CEMS	i. You have installed a CEMS to continuously monitor CO and either O <sub>2</sub> or CO <sub>2</sub> at the outlet of the oxidation catalyst according to the requirements in §63.6625(a); and



For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
		ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and
		iii. The average concentration of CO calculated using §63.6620 is less than or equal to the CO emission limitation. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average concentration measured during the 4-hour period.
7. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and using NSCR	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction, or the average reduction of emissions of THC determined from the initial performance test is equal to or greater than 30 percent; and
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
8. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and not using NSCR	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction or the average reduction of emissions of THC determined from the initial performance test is equal to or greater than 30 percent; and
		ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
9. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR	i. The average formaldehyde concentration, corrected to 15 percent O <sub>2</sub> , dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
10. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR	i. The average formaldehyde concentration, corrected to 15 percent O <sub>2</sub> , dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
11. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP, and existing non-emergency stationary CI RICE 300<HP≤500 located at an area source of HAP	a. Reduce CO emissions	i. The average reduction of emissions of CO or formaldehyde, as applicable determined from the initial performance test is equal to or greater than the required CO or formaldehyde, as applicable, percent reduction.
12. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP, and existing non-emergency stationary CI RICE 300<HP≤500 located at an area source of HAP	a. Limit the concentration of formaldehyde or CO in the stationary RICE exhaust	i. The average formaldehyde or CO concentration, as applicable, corrected to 15 percent O <sub>2</sub> , dry basis, from the three test runs is less than or equal to the formaldehyde or CO emission limitation, as applicable.
13. Existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install an oxidation catalyst	i. You have conducted an initial compliance demonstration as specified in §63.6630(e) to show that the average reduction of emissions of CO is 93 percent or more, or the average CO concentration is less than or equal to 47 ppmvd at 15 percent O <sub>2</sub> ;
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b), or you have installed equipment to automatically shut down the engine if the catalyst inlet temperature exceeds 1350 °F.
14. Existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install NSCR	i. You have conducted an initial compliance demonstration as specified in §63.6630(e) to show that the average reduction of emissions of CO is 75 percent or more, the average CO concentration is less than or equal to 270 ppmvd at 15 percent O <sub>2</sub> , or the average reduction of emissions of THC is 30 percent or more;

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b), or you have installed equipment to automatically shut down the engine if the catalyst inlet temperature exceeds 1250 °F.

[78 FR 6712, Jan. 30, 2013]

**Table 6 to Subpart ZZZZ of Part 63—Continuous Compliance With Emission Limitations, and Other Requirements**

As stated in §63.6640, you must continuously comply with the emissions and operating limitations and work or management practices as required by the following:

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
1. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP	a. Reduce CO emissions and using an oxidation catalyst, and using a CPMS	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved <sup>a</sup> ; and ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
2. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP	a. Reduce CO emissions and not using an oxidation catalyst, and using a CPMS	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved <sup>a</sup> ; and ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
<p>3. New or reconstructed non-emergency 2SLB stationary RICE &gt;500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, new or reconstructed non-emergency stationary CI RICE &gt;500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE &gt;500 HP</p>	<p>a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and using a CEMS</p>	<p>i. Collecting the monitoring data according to §63.6625(a), reducing the measurements to 1-hour averages, calculating the percent reduction or concentration of CO emissions according to §63.6620; and ii. Demonstrating that the catalyst achieves the required percent reduction of CO emissions over the 4-hour averaging period, or that the emission remain at or below the CO concentration limit; and</p>
		<p>iii. Conducting an annual RATA of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B, as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.</p>
<p>4. Non-emergency 4SRB stationary RICE &gt;500 HP located at a major source of HAP</p>	<p>a. Reduce formaldehyde emissions and using NSCR</p>	<p>i. Collecting the catalyst inlet temperature data according to §63.6625(b); and</p>
		<p>ii. Reducing these data to 4-hour rolling averages; and</p>
		<p>iii. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and</p>
		<p>iv. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.</p>
<p>5. Non-emergency 4SRB stationary RICE &gt;500 HP located at a major source of HAP</p>	<p>a. Reduce formaldehyde emissions and not using NSCR</p>	<p>i. Collecting the approved operating parameter (if any) data according to §63.6625(b); and</p>
		<p>ii. Reducing these data to 4-hour rolling averages; and</p>
		<p>iii. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.</p>
<p>6. Non-emergency 4SRB stationary RICE with a brake HP ≥5,000 located at a major source of HAP</p>	<p>a. Reduce formaldehyde emissions</p>	<p>Conducting semiannual performance tests for formaldehyde to demonstrate that the required formaldehyde percent reduction is achieved, or to demonstrate that the average reduction of emissions of THC determined from the performance test is equal to or greater than 30 percent.<sup>a</sup></p>

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
7. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit <sup>a</sup> ; and ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
8. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit <sup>a</sup> ; and ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
9. Existing emergency and black start stationary RICE ≤500 HP located at a major source of HAP, existing non-emergency stationary RICE <100 HP located at a major source of HAP, existing emergency and black start stationary RICE located at an area source of HAP, existing non-emergency stationary CI RICE ≤300 HP located at an area source of HAP, existing non-emergency 2SLB stationary RICE located at an area source of HAP, existing non-emergency stationary SI RICE located at an area source of HAP which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, existing non-emergency 4SLB and 4SRB stationary RICE ≤500 HP located at an area source of HAP, existing non-emergency 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate 24 hours or less per calendar year, and existing non-emergency 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that are remote stationary RICE	a. Work or Management practices	i. Operating and maintaining the stationary RICE according to the manufacturer's emission-related operation and maintenance instructions; or ii. Develop and follow your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
10. Existing stationary CI RICE >500 HP that are not limited use stationary RICE	a. Reduce CO emissions, or limit the concentration of CO in the stationary RICE exhaust, and using oxidation catalyst	i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
11. Existing stationary CI RICE >500 HP that are not limited use stationary RICE	a. Reduce CO emissions, or limit the concentration of CO in the stationary RICE exhaust, and not using oxidation catalyst	i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
12. Existing limited use CI stationary RICE >500 HP	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and using an oxidation catalyst	i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
13. Existing limited use CI stationary RICE >500 HP	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and not using an oxidation catalyst	i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
14. Existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install an oxidation catalyst	i. Conducting annual compliance demonstrations as specified in §63.6640(c) to show that the average reduction of emissions of CO is 93 percent or more, or the average CO concentration is less than or equal to 47 ppmvd at 15 percent O <sub>2</sub> ; and either ii. Collecting the catalyst inlet temperature data according to §63.6625(b), reducing these data to 4-hour rolling averages; and maintaining the 4-hour rolling averages within the limitation of greater than 450 °F and less than or equal to 1350 °F for the catalyst inlet temperature; or iii. Immediately shutting down the engine if the catalyst inlet temperature exceeds 1350 °F.

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
15. Existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install NSCR	i. Conducting annual compliance demonstrations as specified in §63.6640(c) to show that the average reduction of emissions of CO is 75 percent or more, the average CO concentration is less than or equal to 270 ppmvd at 15 percent O <sub>2</sub> , or the average reduction of emissions of THC is 30 percent or more; and either ii. Collecting the catalyst inlet temperature data according to §63.6625(b), reducing these data to 4-hour rolling averages; and maintaining the 4-hour rolling averages within the limitation of greater than or equal to 750 °F and less than or equal to 1250 °F for the catalyst inlet temperature; or iii. Immediately shutting down the engine if the catalyst inlet temperature exceeds 1250 °F.

<sup>a</sup>After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

[78 FR 6715, Jan. 30, 2013]

**Table 7 to Subpart ZZZZ of Part 63—Requirements for Reports**

As stated in §63.6650, you must comply with the following requirements for reports:

For each . . .	You must submit a . . .	The report must contain . . .	You must submit the report . . .
1. Existing non-emergency, non-black start stationary RICE 100≤HP≤500 located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE >500 HP located at a major source of HAP; existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE >300 HP located at an area source of HAP; new or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP; and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP	Compliance report	a. If there are no deviations from any emission limitations or operating limitations that apply to you, a statement that there were no deviations from the emission limitations or operating limitations during the reporting period. If there were no periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), a statement that there were not periods during which the CMS was out-of-control during the reporting period; or	i. Semiannually according to the requirements in §63.6650(b)(1)-(5) for engines that are not limited use stationary RICE subject to numerical emission limitations; and ii. Annually according to the requirements in §63.6650(b)(6)-(9) for engines that are limited use stationary RICE subject to numerical emission limitations.



<b>For each . . .</b>	<b>You must submit a . . .</b>	<b>The report must contain . . .</b>	<b>You must submit the report . . .</b>
		b. If you had a deviation from any emission limitation or operating limitation during the reporting period, the information in §63.6650(d). If there were periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), the information in §63.6650(e); or	i. Semiannually according to the requirements in §63.6650(b).
		c. If you had a malfunction during the reporting period, the information in §63.6650(c)(4).	i. Semiannually according to the requirements in §63.6650(b).
2. New or reconstructed non-emergency stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	Report	a. The fuel flow rate of each fuel and the heating values that were used in your calculations, and you must demonstrate that the percentage of heat input provided by landfill gas or digester gas, is equivalent to 10 percent or more of the gross heat input on an annual basis; and	i. Annually, according to the requirements in §63.6650.
		b. The operating limits provided in your federally enforceable permit, and any deviations from these limits; and	i. See item 2.a.i.
		c. Any problems or errors suspected with the meters.	i. See item 2.a.i.
3. Existing non-emergency, non-black start 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that operate more than 24 hours per calendar year	Compliance report	a. The results of the annual compliance demonstration, if conducted during the reporting period.	i. Semiannually according to the requirements in §63.6650(b)(1)-(5).
4. Emergency stationary RICE that operate for the purposes specified in § 63.6640(f)(4)(ii)	Report	a. The information in §63.6650(h)(1)	i. annually according to the requirements in §63.6650(h)(2)-(3).

[87 FR 48608, Aug. 10, 2022]

**Table 8 to Subpart ZZZZ of Part 63—Applicability of General Provisions to Subpart ZZZZ.**

As stated in §63.6665, you must comply with the following applicable general provisions.

<b>General provisions citation</b>	<b>Subject of citation</b>	<b>Applies to subpart</b>	<b>Explanation</b>
§63.1	General applicability of the General Provisions	Yes.	
§63.2	Definitions	Yes	Additional terms defined in §63.6675.
§63.3	Units and abbreviations	Yes.	

<b>General provisions citation</b>	<b>Subject of citation</b>	<b>Applies to subpart</b>	<b>Explanation</b>
§63.4	Prohibited activities and circumvention	Yes.	
§63.5	Construction and reconstruction	Yes.	
§63.6(a)	Applicability	Yes.	
§63.6(b)(1)-(4)	Compliance dates for new and reconstructed sources	Yes.	
§63.6(b)(5)	Notification	Yes.	
§63.6(b)(6)	[Reserved]		
§63.6(b)(7)	Compliance dates for new and reconstructed area sources that become major sources	Yes.	
§63.6(c)(1)-(2)	Compliance dates for existing sources	Yes.	
§63.6(c)(3)-(4)	[Reserved]		
§63.6(c)(5)	Compliance dates for existing area sources that become major sources	Yes.	
§63.6(d)	[Reserved]		
§63.6(e)	Operation and maintenance	No.	
§63.6(f)(1)	Applicability of standards	No.	
§63.6(f)(2)	Methods for determining compliance	Yes.	
§63.6(f)(3)	Finding of compliance	Yes.	
§63.6(g)(1)-(3)	Use of alternate standard	Yes.	
§63.6(h)	Opacity and visible emission standards	No	Subpart ZZZZ does not contain opacity or visible emission standards.
§63.6(i)	Compliance extension procedures and criteria	Yes.	
§63.6(j)	Presidential compliance exemption	Yes.	
§63.7(a)(1)-(2)	Performance test dates	Yes	Subpart ZZZZ contains performance test dates at §§63.6610, 63.6611, and 63.6612.
§63.7(a)(3)	CAA section 114 authority	Yes.	
§63.7(b)(1)	Notification of performance test	Yes	Except that §63.7(b)(1) only applies as specified in §63.6645.
§63.7(b)(2)	Notification of rescheduling	Yes	Except that §63.7(b)(2) only applies as specified in §63.6645.
§63.7(c)	Quality assurance/test plan	Yes	Except that §63.7(c) only applies as specified in §63.6645.
§63.7(d)	Testing facilities	Yes.	

<b>General provisions citation</b>	<b>Subject of citation</b>	<b>Applies to subpart</b>	<b>Explanation</b>
§63.7(e)(1)	Conditions for conducting performance tests	No.	Subpart ZZZZ specifies conditions for conducting performance tests at §63.6620.
§63.7(e)(2)	Conduct of performance tests and reduction of data	Yes	Subpart ZZZZ specifies test methods at §63.6620.
§63.7(e)(3)	Test run duration	Yes.	
§63.7(e)(4)	Administrator may require other testing under section 114 of the CAA	Yes.	
§63.7(f)	Alternative test method provisions	Yes.	
§63.7(g)	Performance test data analysis, recordkeeping, and reporting	Yes.	
§63.7(h)	Waiver of tests	Yes.	
§63.8(a)(1)	Applicability of monitoring requirements	Yes	Subpart ZZZZ contains specific requirements for monitoring at §63.6625.
§63.8(a)(2)	Performance specifications	Yes.	
§63.8(a)(3)	[Reserved]		
§63.8(a)(4)	Monitoring for control devices	No.	
§63.8(b)(1)	Monitoring	Yes.	
§63.8(b)(2)-(3)	Multiple effluents and multiple monitoring systems	Yes.	
§63.8(c)(1)	Monitoring system operation and maintenance	Yes.	
§63.8(c)(1)(i)	Routine and predictable SSM	No	
§63.8(c)(1)(ii)	SSM not in Startup Shutdown Malfunction Plan	Yes.	
§63.8(c)(1)(iii)	Compliance with operation and maintenance requirements	No	
§63.8(c)(2)-(3)	Monitoring system installation	Yes.	
§63.8(c)(4)	Continuous monitoring system (CMS) requirements	Yes	Except that subpart ZZZZ does not require Continuous Opacity Monitoring System (COMS).
§63.8(c)(5)	COMS minimum procedures	No	Subpart ZZZZ does not require COMS.
§63.8(c)(6)-(8)	CMS requirements	Yes	Except that subpart ZZZZ does not require COMS.
§63.8(d)	CMS quality control	Yes.	
§63.8(e)	CMS performance evaluation	Yes	Except for §63.8(e)(5)(ii), which applies to COMS.

General provisions citation	Subject of citation	Applies to subpart	Explanation
		Except that §63.8(e) only applies as specified in §63.6645.	
§63.8(f)(1)-(5)	Alternative monitoring method	Yes	Except that §63.8(f)(4) only applies as specified in §63.6645.
§63.8(f)(6)	Alternative to relative accuracy test	Yes	Except that §63.8(f)(6) only applies as specified in §63.6645.
§63.8(g)	Data reduction	Yes	Except that provisions for COMS are not applicable. Averaging periods for demonstrating compliance are specified at §§63.6635 and 63.6640.
§63.9(a)	Applicability and State delegation of notification requirements	Yes.	
§63.9(b)(1)-(5)	Initial notifications	Yes	Except that §63.9(b)(3) is reserved.
		Except that §63.9(b) only applies as specified in §63.6645.	
§63.9(c)	Request for compliance extension	Yes	Except that §63.9(c) only applies as specified in §63.6645.
§63.9(d)	Notification of special compliance requirements for new sources	Yes	Except that §63.9(d) only applies as specified in §63.6645.
§63.9(e)	Notification of performance test	Yes	Except that §63.9(e) only applies as specified in §63.6645.
§63.9(f)	Notification of visible emission (VE)/opacity test	No	Subpart ZZZZ does not contain opacity or VE standards.
§63.9(g)(1)	Notification of performance evaluation	Yes	Except that §63.9(g) only applies as specified in §63.6645.
§63.9(g)(2)	Notification of use of COMS data	No	Subpart ZZZZ does not contain opacity or VE standards.
§63.9(g)(3)	Notification that criterion for alternative to RATA is exceeded	Yes	If alternative is in use.
		Except that §63.9(g) only applies as specified in §63.6645.	
§63.9(h)(1)-(6)	Notification of compliance status	Yes	Except that notifications for sources using a CEMS are due 30 days after completion of performance evaluations. §63.9(h)(4) is reserved.
			Except that §63.9(h) only applies as specified in §63.6645.
§63.9(i)	Adjustment of submittal deadlines	Yes.	
§63.9(j)	Change in previous information	Yes.	

<b>General provisions citation</b>	<b>Subject of citation</b>	<b>Applies to subpart</b>	<b>Explanation</b>
§63.9(k)	Electronic reporting procedures	Yes	Only as specified in §63.9(j).
§63.10(a)	Administrative provisions for recordkeeping/reporting	Yes.	
§63.10(b)(1)	Record retention	Yes	Except that the most recent 2 years of data do not have to be retained on site.
§63.10(b)(2)(i)-(v)	Records related to SSM	No.	
§63.10(b)(2)(vi)-(xi)	Records	Yes.	
§63.10(b)(2)(xii)	Record when under waiver	Yes.	
§63.10(b)(2)(xiii)	Records when using alternative to RATA	Yes	For CO standard if using RATA alternative.
§63.10(b)(2)(xiv)	Records of supporting documentation	Yes.	
§63.10(b)(3)	Records of applicability determination	Yes.	
§63.10(c)	Additional records for sources using CEMS	Yes	Except that §63.10(c)(2)-(4) and (9) are reserved.
§63.10(d)(1)	General reporting requirements	Yes.	
§63.10(d)(2)	Report of performance test results	Yes.	
§63.10(d)(3)	Reporting opacity or VE observations	No	Subpart ZZZZ does not contain opacity or VE standards.
§63.10(d)(4)	Progress reports	Yes.	
§63.10(d)(5)	Startup, shutdown, and malfunction reports	No.	
§63.10(e)(1) and (2)(i)	Additional CMS Reports	Yes.	
§63.10(e)(2)(ii)	COMS-related report	No	Subpart ZZZZ does not require COMS.
§63.10(e)(3)	Excess emission and parameter exceedances reports	Yes.	Except that §63.10(e)(3)(i) (C) is reserved.
§63.10(e)(4)	Reporting COMS data	No	Subpart ZZZZ does not require COMS.
§63.10(f)	Waiver for recordkeeping/reporting	Yes.	
§63.11	Flares	No.	
§63.12	State authority and delegations	Yes.	
§63.13	Addresses	Yes.	
§63.14	Incorporation by reference	Yes.	
§63.15	Availability of information	Yes.	

## Appendix A to Subpart ZZZZ of Part 63—Protocol for Using an Electrochemical Analyzer to Determine Oxygen and Carbon Monoxide Concentrations From Certain Engines

### 1.0 SCOPE AND APPLICATION. WHAT IS THIS PROTOCOL?

This protocol is a procedure for using portable electrochemical (EC) cells for measuring carbon monoxide (CO) and oxygen (O<sub>2</sub>) concentrations in controlled and uncontrolled emissions from existing stationary 4-stroke lean burn and 4-stroke rich burn reciprocating internal combustion engines as specified in the applicable rule.

#### 1.1 Analytes. What does this protocol determine?

This protocol measures the engine exhaust gas concentrations of carbon monoxide (CO) and oxygen (O<sub>2</sub>).

Analyte	CAS No.	Sensitivity
Carbon monoxide (CO)	630-08-0	Minimum detectable limit should be 2 percent of the nominal range or 1 ppm, whichever is less restrictive.
Oxygen (O <sub>2</sub> )	7782-44-7	

#### 1.2 Applicability. When is this protocol acceptable?

This protocol is applicable to 40 CFR part 63, subpart ZZZZ. Because of inherent cross sensitivities of EC cells, you must not apply this protocol to other emissions sources without specific instruction to that effect.

#### 1.3 Data Quality Objectives. How good must my collected data be?

Refer to Section 13 to verify and document acceptable analyzer performance.

#### 1.4 Range. What is the targeted analytical range for this protocol?

The measurement system and EC cell design(s) conforming to this protocol will determine the analytical range for each gas component. The nominal ranges are defined by choosing up-scale calibration gas concentrations near the maximum anticipated flue gas concentrations for CO and O<sub>2</sub>, or no more than twice the permitted CO level.

#### 1.5 Sensitivity. What minimum detectable limit will this protocol yield for a particular gas component?

The minimum detectable limit depends on the nominal range and resolution of the specific EC cell used, and the signal to noise ratio of the measurement system. The minimum detectable limit should be 2 percent of the nominal range or 1 ppm, whichever is less restrictive.

### 2.0 SUMMARY OF PROTOCOL

In this protocol, a gas sample is extracted from an engine exhaust system and then conveyed to a portable EC analyzer for measurement of CO and O<sub>2</sub> gas concentrations. This method provides measurement system performance specifications and sampling protocols to ensure reliable data. You may use additions to, or modifications of vendor supplied measurement systems (e.g., heated or unheated sample lines, thermocouples, flow meters, selective gas scrubbers, etc.) to meet the design specifications of this protocol. Do not make changes to the measurement system from the as-verified configuration (Section 3.12).

### 3.0 DEFINITIONS

**3.1 Measurement System.** The total equipment required for the measurement of CO and O<sub>2</sub> concentrations. The measurement system consists of the following major subsystems:

**3.1.1 Data Recorder.** A strip chart recorder, computer or digital recorder for logging measurement data from the analyzer output. You may record measurement data from the digital data display manually or electronically.

**3.1.2 Electrochemical (EC) Cell.** A device, similar to a fuel cell, used to sense the presence of a specific analyte and generate an electrical current output proportional to the analyte concentration.

**3.1.3 Interference Gas Scrubber.** A device used to remove or neutralize chemical compounds that may interfere with the selective operation of an EC cell.

**3.1.4 Moisture Removal System.** Any device used to reduce the concentration of moisture in the sample stream so as to protect the EC cells from the damaging effects of condensation and to minimize errors in measurements caused by the scrubbing of soluble gases.

**3.1.5 Sample Interface.** The portion of the system used for one or more of the following: sample acquisition; sample transport; sample conditioning or protection of the EC cell from any degrading effects of the engine exhaust effluent; removal of particulate matter and condensed moisture.

**3.2 Nominal Range.** The range of analyte concentrations over which each EC cell is operated (normally 25 percent to 150 percent of up-scale calibration gas value). Several nominal ranges can be used for any given cell so long as the calibration and repeatability checks for that range remain within specifications.

**3.3 Calibration Gas.** A vendor certified concentration of a specific analyte in an appropriate balance gas.

**3.4 Zero Calibration Error.** The analyte concentration output exhibited by the EC cell in response to zero-level calibration gas.

**3.5 Up-Scale Calibration Error.** The mean of the difference between the analyte concentration exhibited by the EC cell and the certified concentration of the up-scale calibration gas.

**3.6 Interference Check.** A procedure for quantifying analytical interference from components in the engine exhaust gas other than the targeted analytes.

**3.7 Repeatability Check.** A protocol for demonstrating that an EC cell operated over a given nominal analyte concentration range provides a stable and consistent response and is not significantly affected by repeated exposure to that gas.

**3.8 Sample Flow Rate.** The flow rate of the gas sample as it passes through the EC cell. In some situations, EC cells can experience drift with changes in flow rate. The flow rate must be monitored and documented during all phases of a sampling run.

**3.9 Sampling Run.** A timed three-phase event whereby an EC cell's response rises and plateaus in a sample conditioning phase, remains relatively constant during a measurement data phase, then declines during a refresh phase. The sample conditioning phase exposes the EC cell to the gas sample for a length of time sufficient to reach a constant response. The measurement data phase is the time interval during which gas sample measurements can be made that meet the acceptance criteria of this protocol. The refresh phase then purges the EC cells with CO-free air. The refresh phase replenishes requisite O<sub>2</sub> and moisture in the electrolyte reserve and provides a mechanism to de-gas or desorb any interference gas scrubbers or filters so as to enable a stable CO EC cell response. There are four primary types of sampling runs: pre-sampling calibrations; stack gas sampling; post-sampling calibration checks; and measurement system repeatability checks. Stack gas sampling runs can be chained together for extended evaluations, providing all other procedural specifications are met.

**3.10 Sampling Day.** A time not to exceed twelve hours from the time of the pre-sampling calibration to the post-sampling calibration check. During this time, stack gas sampling runs can be repeated without repeated recalibrations, providing all other sampling specifications have been met.

**3.11 Pre-Sampling Calibration/Post-Sampling Calibration Check.** The protocols executed at the beginning and end of each sampling day to bracket measurement readings with controlled performance checks.

**3.12 Performance-Established Configuration.** The EC cell and sampling system configuration that existed at the time that it initially met the performance requirements of this protocol.

#### 4.0 INTERFERENCES.

When present in sufficient concentrations, NO and NO<sub>2</sub> are two gas species that have been reported to interfere with CO concentration measurements. In the likelihood of this occurrence, it is the protocol user's responsibility to employ and properly maintain an appropriate CO EC cell filter or scrubber for removal of these gases, as described in Section 6.2.12.

#### 5.0 SAFETY. [RESERVED]

#### 6.0 EQUIPMENT AND SUPPLIES.

##### 6.1 What equipment do I need for the measurement system?

The system must maintain the gas sample at conditions that will prevent moisture condensation in the sample transport lines, both before and as the sample gas contacts the EC cells. The essential components of the measurement system are described below.

##### 6.2 Measurement System Components.

**6.2.1 Sample Probe.** A single extraction-point probe constructed of glass, stainless steel or other non-reactive material, and of length sufficient to reach any designated sampling point. The sample probe must be designed to prevent plugging due to condensation or particulate matter.

**6.2.2 Sample Line.** Non-reactive tubing to transport the effluent from the sample probe to the EC cell.

**6.2.3 Calibration Assembly (optional).** A three-way valve assembly or equivalent to introduce calibration gases at ambient pressure at the exit end of the sample probe during calibration checks. The assembly must be designed such that only stack gas or calibration gas flows in the sample line and all gases flow through any gas path filters.

**6.2.4 Particulate Filter (optional).** Filters before the inlet of the EC cell to prevent accumulation of particulate material in the measurement system and extend the useful life of the components. All filters must be fabricated of materials that are non-reactive to the gas mixtures being sampled.

**6.2.5 Sample Pump.** A leak-free pump to provide undiluted sample gas to the system at a flow rate sufficient to minimize the response time of the measurement system. If located upstream of the EC cells, the pump must be constructed of a material that is non-reactive to the gas mixtures being sampled.

**6.2.8 Sample Flow Rate Monitoring.** An adjustable rotameter or equivalent device used to adjust and maintain the sample flow rate through the analyzer as prescribed.

**6.2.9 Sample Gas Manifold (optional).** A manifold to divert a portion of the sample gas stream to the analyzer and the remainder to a by-pass discharge vent. The sample gas manifold may also include provisions for introducing calibration gases directly to the analyzer. The manifold must be constructed of a material that is non-reactive to the gas mixtures being sampled.

**6.2.10 EC cell.** A device containing one or more EC cells to determine the CO and O<sub>2</sub> concentrations in the sample gas stream. The EC cell(s) must meet the applicable performance specifications of Section 13 of this protocol.

**6.2.11 Data Recorder.** A strip chart recorder, computer or digital recorder to make a record of analyzer output data. The data recorder resolution (i.e., readability) must be no greater than 1 ppm for CO; 0.1 percent for O<sub>2</sub>; and one degree (either °C or °F) for temperature. Alternatively, you may use a digital or analog meter having the same resolution to observe and manually record the analyzer responses.



**6.2.12 Interference Gas Filter or Scrubber.** A device to remove interfering compounds upstream of the CO EC cell. Specific interference gas filters or scrubbers used in the performance-established configuration of the analyzer must continue to be used. Such a filter or scrubber must have a means to determine when the removal agent is exhausted. Periodically replace or replenish it in accordance with the manufacturer's recommendations.

## 7.0 REAGENTS AND STANDARDS. WHAT CALIBRATION GASES ARE NEEDED?

**7.1 Calibration Gases.** CO calibration gases for the EC cell must be CO in nitrogen or CO in a mixture of nitrogen and O<sub>2</sub>. Use CO calibration gases with labeled concentration values certified by the manufacturer to be within  $\pm 5$  percent of the label value. Dry ambient air (20.9 percent O<sub>2</sub>) is acceptable for calibration of the O<sub>2</sub> cell. If needed, any lower percentage O<sub>2</sub> calibration gas must be a mixture of O<sub>2</sub> in nitrogen.

**7.1.1 Up-Scale CO Calibration Gas Concentration.** Choose one or more up-scale gas concentrations such that the average of the stack gas measurements for each stack gas sampling run are between 25 and 150 percent of those concentrations. Alternatively, choose an up-scale gas that does not exceed twice the concentration of the applicable outlet standard. If a measured gas value exceeds 150 percent of the up-scale CO calibration gas value at any time during the stack gas sampling run, the run must be discarded and repeated.

### 7.1.2 Up-Scale O<sub>2</sub> Calibration Gas Concentration.

Select an O<sub>2</sub> gas concentration such that the difference between the gas concentration and the average stack gas measurement or reading for each sample run is less than 15 percent O<sub>2</sub>. When the average exhaust gas O<sub>2</sub> readings are above 6 percent, you may use dry ambient air (20.9 percent O<sub>2</sub>) for the up-scale O<sub>2</sub> calibration gas.

**7.1.3 Zero Gas.** Use an inert gas that contains less than 0.25 percent of the up-scale CO calibration gas concentration. You may use dry air that is free from ambient CO and other combustion gas products (e.g., CO<sub>2</sub>).

## 8.0 SAMPLE COLLECTION AND ANALYSIS

### 8.1 Selection of Sampling Sites.

**8.1.1 Control Device Inlet.** Select a sampling site sufficiently downstream of the engine so that the combustion gases should be well mixed. Use a single sampling extraction point near the center of the duct (e.g., within the 10 percent centroidal area), unless instructed otherwise.

**8.1.2 Exhaust Gas Outlet.** Select a sampling site located at least two stack diameters downstream of any disturbance (e.g., turbocharger exhaust, crossover junction or recirculation take-off) and at least one-half stack diameter upstream of the gas discharge to the atmosphere. Use a single sampling extraction point near the center of the duct (e.g., within the 10 percent centroidal area), unless instructed otherwise.

**8.2 Stack Gas Collection and Analysis.** Prior to the first stack gas sampling run, conduct that the pre-sampling calibration in accordance with Section 10.1. Use Figure 1 to record all data. Zero the analyzer with zero gas. Confirm and record that the scrubber media color is correct and not exhausted. Then position the probe at the sampling point and begin the sampling run at the same flow rate used during the up-scale calibration. Record the start time. Record all EC cell output responses and the flow rate during the "sample conditioning phase" once per minute until constant readings are obtained. Then begin the "measurement data phase" and record readings every 15 seconds for at least two minutes (or eight readings), or as otherwise required to achieve two continuous minutes of data that meet the specification given in Section 13.1. Finally, perform the "refresh phase" by introducing dry air, free from CO and other combustion gases, until several minute-to-minute readings of consistent value have been obtained. For each run use the "measurement data phase" readings to calculate the average stack gas CO and O<sub>2</sub> concentrations.

**8.3 EC Cell Rate.** Maintain the EC cell sample flow rate so that it does not vary by more than  $\pm 10$  percent throughout the pre-sampling calibration, stack gas sampling and post-sampling calibration check. Alternatively, the EC cell sample flow rate can be maintained within a tolerance range that does not affect the gas concentration readings by more than  $\pm 3$  percent, as instructed by the EC cell manufacturer.

## 9.0 QUALITY CONTROL (RESERVED)

## 10.0 CALIBRATION AND STANDARDIZATION

**10.1 Pre-Sampling Calibration.** Conduct the following protocol once for each nominal range to be used on each EC cell before performing a stack gas sampling run on each field sampling day. Repeat the calibration if you replace an EC cell before completing all of the sampling runs. There is no prescribed order for calibration of the EC cells; however, each cell must complete the measurement data phase during calibration. Assemble the measurement system by following the manufacturer's recommended protocols including for preparing and preconditioning the EC cell. Assure the measurement system has no leaks and verify the gas scrubbing agent is not depleted. Use Figure 1 to record all data.

**10.1.1 Zero Calibration.** For both the O<sub>2</sub> and CO cells, introduce zero gas to the measurement system (e.g., at the calibration assembly) and record the concentration reading every minute until readings are constant for at least two consecutive minutes. Include the time and sample flow rate. Repeat the steps in this section at least once to verify the zero calibration for each component gas.

**10.1.2 Zero Calibration Tolerance.** For each zero gas introduction, the zero level output must be less than or equal to  $\pm 3$  percent of the up-scale gas value or  $\pm 1$  ppm, whichever is less restrictive, for the CO channel and less than or equal to  $\pm 0.3$  percent O<sub>2</sub> for the O<sub>2</sub> channel.

**10.1.3 Up-Scale Calibration.** Individually introduce each calibration gas to the measurement system (e.g., at the calibration assembly) and record the start time. Record all EC cell output responses and the flow rate during this "sample conditioning phase" once per minute until readings are constant for at least two minutes. Then begin the "measurement data phase" and record readings every 15 seconds for a total of two minutes, or as otherwise required. Finally, perform the "refresh phase" by introducing dry air, free from CO and other combustion gases, until readings are constant for at least two consecutive minutes. Then repeat the steps in this section at least once to verify the calibration for each component gas. Introduce all gases to flow through the entire sample handling system (i.e., at the exit end of the sampling probe or the calibration assembly).

**10.1.4 Up-Scale Calibration Error.** The mean of the difference of the "measurement data phase" readings from the reported standard gas value must be less than or equal to  $\pm 5$  percent or  $\pm 1$  ppm for CO or  $\pm 0.5$  percent O<sub>2</sub>, whichever is less restrictive, respectively. The maximum allowable deviation from the mean measured value of any single "measurement data phase" reading must be less than or equal to  $\pm 2$  percent or  $\pm 1$  ppm for CO or  $\pm 0.5$  percent O<sub>2</sub>, whichever is less restrictive, respectively.

**10.2 Post-Sampling Calibration Check.** Conduct a stack gas post-sampling calibration check after the stack gas sampling run or set of runs and within 12 hours of the initial calibration. Conduct up-scale and zero calibration checks using the protocol in Section 10.1. Make no changes to the sampling system or EC cell calibration until all post-sampling calibration checks have been recorded. If either the zero or up-scale calibration error exceeds the respective specification in Sections 10.1.2 and 10.1.4 then all measurement data collected since the previous successful calibrations are invalid and re-calibration and re-sampling are required. If the sampling system is disassembled or the EC cell calibration is adjusted, repeat the calibration check before conducting the next analyzer sampling run.

## 11.0 ANALYTICAL PROCEDURE

The analytical procedure is fully discussed in Section 8.

## 12.0 CALCULATIONS AND DATA ANALYSIS

Determine the CO and O<sub>2</sub> concentrations for each stack gas sampling run by calculating the mean gas concentrations of the data recorded during the "measurement data phase".

## 13.0 PROTOCOL PERFORMANCE

Use the following protocols to verify consistent analyzer performance during each field sampling day.

**13.1 Measurement Data Phase Performance Check.** Calculate the mean of the readings from the “measurement data phase”. The maximum allowable deviation from the mean for each of the individual readings is  $\pm 2$  percent, or  $\pm 1$  ppm, whichever is less restrictive. Record the mean value and maximum deviation for each gas monitored. Data must conform to Section 10.1.4. The EC cell flow rate must conform to the specification in Section 8.3.

*Example:* A measurement data phase is invalid if the maximum deviation of any single reading comprising that mean is greater than  $\pm 2$  percent or  $\pm 1$  ppm (the default criteria). For example, if the mean = 30 ppm, single readings of below 29 ppm and above 31 ppm are disallowed).

**13.2 Interference Check.** Before the initial use of the EC cell and interference gas scrubber in the field, and semi-annually thereafter, challenge the interference gas scrubber with NO and NO<sub>2</sub> gas standards that are generally recognized as representative of diesel-fueled engine NO and NO<sub>2</sub> emission values. Record the responses displayed by the CO EC cell and other pertinent data on Figure 1 or a similar form.

**13.2.1 Interference Response.** The combined NO and NO<sub>2</sub> interference response should be less than or equal to  $\pm 5$  percent of the up-scale CO calibration gas concentration.

**13.3 Repeatability Check.** Conduct the following check once for each nominal range that is to be used on the CO EC cell within 5 days prior to each field sampling program. If a field sampling program lasts longer than 5 days, repeat this check every 5 days. Immediately repeat the check if the EC cell is replaced or if the EC cell is exposed to gas concentrations greater than 150 percent of the highest up-scale gas concentration.

**13.3.1 Repeatability Check Procedure.** Perform a complete EC cell sampling run (all three phases) by introducing the CO calibration gas to the measurement system and record the response. Follow Section 10.1.3. Use Figure 1 to record all data. Repeat the run three times for a total of four complete runs. During the four repeatability check runs, do not adjust the system except where necessary to achieve the correct calibration gas flow rate at the analyzer.

**13.3.2 Repeatability Check Calculations.** Determine the highest and lowest average “measurement data phase” CO concentrations from the four repeatability check runs and record the results on Figure 1 or a similar form. The absolute value of the difference between the maximum and minimum average values recorded must not vary more than  $\pm 3$  percent or  $\pm 1$  ppm of the up-scale gas value, whichever is less restrictive.

14.0 POLLUTION PREVENTION (RESERVED)

15.0 WASTE MANAGEMENT (RESERVED)

16.0 ALTERNATIVE PROCEDURES (RESERVED)

17.0 REFERENCES

(1) “Development of an Electrochemical Cell Emission Analyzer Test Protocol”, Topical Report, Phil Juneau, Emission Monitoring, Inc., July 1997.

(2) “Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Emissions from Natural Gas-Fired Engines, Boilers, and Process Heaters Using Portable Analyzers”, EMC Conditional Test Protocol 30 (CTM-30), Gas Research Institute Protocol GRI-96/0008, Revision 7, October 13, 1997.

(3) “ICAC Test Protocol for Periodic Monitoring”, EMC Conditional Test Protocol 34 (CTM-034), The Institute of Clean Air Companies, September 8, 1999.

(4) “Code of Federal Regulations”, Protection of Environment, 40 CFR, Part 60, Appendix A, Methods 1-4; 10.

**TABLE 1: APPENDIX A—SAMPLING RUN DATA.**

Facility_____	Engine I.D._____	Date_____
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Facility	Engine I.D.	Date
"		

[78 FR 6721, Jan. 30, 2013]

## Attachment E

### Part 70 Operating Permit No: 165-47094-00001

[Downloaded from the eCFR on June 6, 2023]

#### Electronic Code of Federal Regulations

#### Title 40: Protection of Environment

#### PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

#### Subpart UUUUU—National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units

**Source:** 77 FR 9464, Feb. 16, 2012, unless otherwise noted.

#### What This Subpart Covers

##### § 63.9980 What is the purpose of this subpart?

This subpart establishes national emission limitations and work practice standards for hazardous air pollutants (HAP) emitted from coal- and oil-fired electric utility steam generating units (EGUs) as defined in § 63.10042 of this subpart. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations.

##### § 63.9981 Am I subject to this subpart?

You are subject to this subpart if you own or operate a coal-fired EGU or an oil-fired EGU as defined in § 63.10042 of this subpart.

##### § 63.9982 What is the affected source of this subpart?

(a) This subpart applies to each individual or group of two or more new, reconstructed, or existing affected source(s) as described in paragraphs (a)(1) and (2) of this section within a contiguous area and under common control.

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

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

(b) An EGU is new if you commence construction of the coal- or oil-fired EGU after May 3, 2011.

(c) An EGU is reconstructed if you meet the reconstruction criteria as defined in § 63.2, and if you commence reconstruction after May 3, 2011.

(d) An EGU is existing if it is not new or reconstructed. An existing electric steam generating unit that meets the applicability requirements after April 16, 2012, due to a change in process (*e.g.*, fuel or utilization) is considered to be an existing source under this subpart.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23402, Apr. 19, 2012; 78 FR 24084, Apr. 24, 2013; 85 FR 20850, Apr. 15, 2020]

**§ 63.9983 Are any fossil fuel-fired electric generating units not subject to this subpart?**

The types of electric steam generating units listed in paragraphs (a) through (d) of this section are not subject to this subpart.

(a) Any unit designated as a major source stationary combustion turbine subject to subpart YYYY of this part and any unit designated as an area source stationary combustion turbine, other than an integrated gasification combined cycle (IGCC) unit.

(b) Any electric utility steam generating unit that is not a coal- or oil-fired EGU and that meets the definition of a natural gas-fired EGU in § 63.10042.

(c) Any electric utility steam generating unit that has the capability of combusting more than 25 MW of coal or oil but does not meet the definition of a coal- or oil-fired EGU because it did not fire sufficient coal or oil to satisfy the average annual heat input requirement set forth in the definitions for coal-fired and oil-fired EGUs in § 63.10042. Heat input means heat derived from combustion of fuel in an EGU and does not include the heat derived from preheated combustion air, recirculated flue gases or exhaust gases from other sources (such as stationary gas turbines, internal combustion engines, and industrial boilers).

(d) Any electric steam generating unit combusting solid waste is a solid waste incineration unit subject to standards established under sections 129 and 111 of the Clean Air Act.

(e) Any electric utility steam generating unit that meets the definition of a natural gas-fired EGU under this subpart and that fires at least 10 percent biomass is an industrial boiler subject to standards established under subpart DDDDD of this part, if it otherwise meets the applicability provisions in that rule.

[77 FR 9464, Feb. 16, 2012, as amended at 81 FR 20180, Apr. 6, 2016]

**§ 63.9984 When do I have to comply with this subpart?**

(a) If you have a new or reconstructed EGU, you must comply with this subpart by April 16, 2012 or upon startup of your EGU, whichever is later, and as further provided for in § 63.10005(g).

(b) If you have an existing EGU, you must comply with this subpart no later than April 16, 2015, except as provided in paragraph (g) of this section.

(c) You must meet the notification requirements in § 63.10030 according to the schedule in § 63.10030 and in subpart A of this part. Some of the notifications must be submitted before you are required to comply with the emission limits and work practice standards in this subpart.

(d) An electric steam generating unit that does not meet the definition of an EGU subject to this subpart on April 16, 2012 for new sources or April 16, 2015 for existing sources must comply with the applicable existing source provisions of this subpart on the date such unit meets the definition of an EGU subject to this subpart.

(e) If you own or operate an electric steam generating unit that is exempted from this subpart under § 63.9983(d), if the manner of operating the unit changes such that the combustion of waste is discontinued and the unit becomes a coal-fired or oil-fired EGU (as defined in § 63.10042), you must be in compliance with this subpart on April 16, 2015 or on the effective date of the switch from waste combustion to coal or oil combustion, whichever is later.

(f) You must demonstrate that compliance has been achieved, by conducting the required performance tests and other activities, no later than 180 days after the applicable date in paragraph (a), (b), (c), (d), (e), or (g) of this section.

(g) If you own or operate an EGU that is in the *Unit designed for eastern bituminous coal refuse (EBCR) subcategory* as defined in § 63.10042, you must comply with the applicable hydrogen chloride (HCl) or sulfur dioxide (SO<sub>2</sub>) requirements of this subpart no later than April 15, 2020.

[77 FR 9464, Feb. 16, 2012, as amended at 85 FR 20850, Apr. 15, 2020]

**§ 63.9985 What is a new EGU?**

(a) A new EGU is an EGU that meets any of the criteria specified in paragraph (a)(1) through (a)(2) of this section.

(1) An EGU that commenced construction after May 3, 2011.

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

(b) [Reserved]

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23402, Apr. 19, 2012]

**Emission Limitations and Work Practice Standards**

**§ 63.9990 What are the subcategories of EGUs?**

(a) Coal-fired EGUs are subcategorized as defined in paragraphs (a)(1) through (3) of this section and as defined in § 63.10042.

(1) EGUs designed for coal with a heating value greater than or equal to 8,300 Btu/lb,

(2) EGUs designed for low rank virgin coal, and

(3) EGUs designed for EBCR.

(b) Oil-fired EGUs are subcategorized as noted in paragraphs (b)(1) through (b)(4) of this section and as defined in § 63.10042.

(1) Continental liquid oil-fired EGUs

(2) Non-continental liquid oil-fired EGUs,

(3) Limited-use liquid oil-fired EGUs, and

(4) EGUs designed to burn solid oil-derived fuel.

(c) IGCC units combusting either gasified coal or gasified solid oil-derived fuel. For purposes of compliance, monitoring, recordkeeping, and reporting requirements in this subpart, IGCC units are subject in the same manner as coal-fired units and solid oil-derived fuel-fired units, unless otherwise indicated.

[77 FR 9464, Feb. 16, 2012, as amended at 85 FR 20850, Apr. 15, 2020]



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

(a) You must meet the requirements in paragraphs (a)(1) and (2) of this section. You must meet these requirements at all times.

(1) You must meet each emission limit and work practice standard in Table 1 through 3 to this subpart that applies to your EGU, for each EGU at your source, except as provided under § 63.10009.

(2) You must meet each operating limit in Table 4 to this subpart that applies to your EGU.

(b) As provided in § 63.6(g), the Administrator may approve use of an alternative to the work practice standards in this section.

(c) You may use the alternate SO<sub>2</sub> limit in Tables 1 and 2 to this subpart only if your EGU:

(1) Has a system using wet or dry flue gas desulfurization technology and an SO<sub>2</sub> continuous emissions monitoring system (CEMS) installed on the EGU; and

(2) At all times, you operate the wet or dry flue gas desulfurization technology and the SO<sub>2</sub> CEMS installed on the EGU consistent with § 63.10000(b).

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23402, Apr. 19, 2012; 81 FR 20180, Apr. 6, 2016]

**General Compliance Requirements**

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

(a) You must be in compliance with the emission limits and operating limits in this subpart. These limits apply to you at all times except during periods of startup and shutdown; however, for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs, you are required to meet the work practice requirements, items 3 and 4, in Table 3 to this subpart during periods of startup or shutdown.

(b) At all times you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the EPA Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

(c)

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

(i) For a coal-fired or solid oil-derived fuel-fired EGU or IGCC EGU, you may conduct initial performance testing in accordance with § 63.10005(h), to determine whether the EGU qualifies as a low emitting EGU (LEE) for one or more applicable emission limits, except as otherwise provided in paragraphs (c)(1)(i)(A) and (B) of this section:

(A) Except as provided in paragraph (c)(1)(i)(C) of this section, you may not pursue the LEE option if your coal-fired, IGCC, or solid oil-derived fuel-fired EGU is equipped with a main stack and a bypass stack or bypass duct configuration that allows the effluent to bypass any pollutant control device.

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

(C) You may pursue the LEE option provided that:

(1) Your EGU's control device bypass emissions are measured in the bypass stack or duct or your control device bypass exhaust is routed through the EGU main stack so that emissions are measured during the bypass event; or

(2) Except for hours during which only clean fuel is combusted, you bypass your EGU control device only during emergency periods for no more than a total of 2 percent of your EGU's annual operating hours; you use clean fuels to the maximum extent possible during an emergency period; and you prepare and submit a report describing the emergency event, its cause, corrective action taken, and estimates of emissions released during the emergency event. You must include these emergency emissions along with performance test results in assessing whether your EGU maintains LEE status.

(ii) For a qualifying LEE for Hg emissions limits, you must conduct a 30-day performance test using Method 30B at least once every 12 calendar months to demonstrate continued LEE status.

(iii) For a qualifying LEE of any other applicable emissions limits, you must conduct a performance test at least once every 36 calendar months to demonstrate continued LEE status.

(iv) If your coal-fired or solid oil derived fuel-fired EGU or IGCC EGU does not qualify as a LEE for total non-mercury HAP metals, individual non-mercury HAP metals, or filterable particulate matter (PM), you must demonstrate compliance through an initial performance test and you must monitor continuous performance through either use of a particulate matter continuous parametric monitoring system (PM CPMS), a PM CEMS, or, for an existing EGU, compliance performance testing repeated quarterly.

(v) If your coal-fired or solid oil-derived fuel-fired EGU does not qualify as a LEE for hydrogen chloride (HCl), you may demonstrate initial and continuous compliance through use of an HCl CEMS, installed and operated in accordance with Appendix B to this subpart. As an alternative to HCl CEMS, you may demonstrate initial and continuous compliance by conducting an initial and periodic quarterly performance stack test for HCl. If your EGU uses wet or dry flue gas desulfurization technology (this includes limestone injection into a fluidized bed combustion unit), you may apply a second alternative to HCl CEMS by installing and operating a sulfur dioxide (SO<sub>2</sub>) CEMS installed and operated in accordance with part 75 of this chapter to demonstrate compliance with the applicable SO<sub>2</sub> emissions limit.

(vi) If your coal-fired or solid oil-derived fuel-fired EGU does not qualify as a LEE for Hg, you must demonstrate initial and continuous compliance through use of a Hg CEMS or a sorbent trap monitoring system, in accordance with appendix A to this subpart.

(A) You may choose to use separate sorbent trap monitoring systems to comply with this subpart: One sorbent trap monitoring system to demonstrate compliance with the numeric mercury emissions limit during periods other than startup or shutdown and the other sorbent trap monitoring system to report average mercury concentration during startup periods or shutdown periods.

(B) You may choose to use one sorbent trap monitoring system to demonstrate compliance with the mercury emissions limit at all times (including startup periods and shutdown periods) and to report average mercury concentration. You must follow the startup or shutdown requirements that follow and as given in Table 3 to this subpart for each coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGU.

(2) For liquid oil-fired EGUs, except limited use liquid oil-fired EGUs, initial performance testing is required for all pollutants, to demonstrate compliance with the applicable emission limits.

(i) For an existing liquid oil-fired unit, you may conduct the performance testing in accordance with § 63.10005(h), to determine whether the unit qualifies as a LEE for one or more pollutants. For a qualifying LEE for Hg emissions limits, you must conduct a 30-day performance test using Method 30B at least once every 12 calendar months to demonstrate continued LEE status. For a qualifying LEE of any other applicable emissions limits, you must conduct a performance test at least once every 36 calendar months to demonstrate continued LEE status.

(ii) If your liquid oil-fired unit does not qualify as a LEE for total HAP metals (including mercury), individual metals (including mercury), or filterable PM you must demonstrate compliance through an initial performance test and you must monitor continuous performance through either use of a PM CPMS, a PM CEMS, or, for an existing EGU, performance testing conducted quarterly.

(iii) If your existing liquid oil-fired unit does not qualify as a LEE for hydrogen chloride (HCl) or for hydrogen fluoride (HF), you may demonstrate initial and continuous compliance through use of an HCl CEMS, an HF CEMS, or an HCl and HF CEMS, installed and operated in accordance with Appendix B to this rule. As an alternative to HCl CEMS, HF CEMS, or HCl and HF CEMS, you may demonstrate initial and continuous compliance through quarterly performance testing and parametric monitoring for HCl and HF. If you choose to use quarterly testing and parametric monitoring, then you must also develop a site-specific monitoring plan that identifies the CMS you will use to ensure that the operations of the EGU remains consistent with those during the performance test. As another alternative, you may measure or obtain, and keep records of, fuel moisture content; as long as fuel moisture does not exceed 1.0 percent by weight, you need not conduct other HCl or HF monitoring or testing.

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

(d)

(1) If you demonstrate compliance with any applicable emissions limit through use of a continuous monitoring system (CMS), where a CMS includes a continuous parameter monitoring system (CPMS) as well as a continuous emissions monitoring system (CEMS), you must develop a site-specific monitoring plan and submit this site-specific monitoring plan, if requested, at least 60 days before your initial performance evaluation (where applicable) of your CMS. This requirement also applies to you if you petition the Administrator for alternative monitoring parameters under § 63.8(f). This requirement to develop and submit a site-specific monitoring plan does not apply to affected sources with existing monitoring plans that apply to CEMS and CPMS prepared under appendix B to part 60 or part 75 of this chapter, and that meet the requirements of § 63.10010. Using the process described in § 63.8(f)(4), you may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in this paragraph of this section and, if approved, include those in your site-specific monitoring plan. The monitoring plan must address the provisions in paragraphs (d)(2) through (5) of this section.

(2) The site-specific monitoring plan shall include the information specified in paragraphs (d)(5)(i) through (d)(5)(vii) of this section. Alternatively, the requirements of paragraphs (d)(5)(i) through (d)(5)(vii) are considered to be met for a particular CMS or sorbent trap monitoring system if:

(i) The CMS or sorbent trap monitoring system is installed, certified, maintained, operated, and quality-assured either according to part 75 of this chapter, or appendix A or B to this subpart; and

(ii) The recordkeeping and reporting requirements of part 75 of this chapter, or appendix A or B to this subpart, that pertain to the CMS are met.

(3) If requested by the Administrator, you must submit the monitoring plan (or relevant portion of the plan) at least 60 days before the initial performance evaluation of a particular CMS, except where the CMS has already undergone a performance evaluation that meets the requirements of § 63.10010 (e.g., if the CMS was previously certified under another program).

(4) You must operate and maintain the CMS according to the site-specific monitoring plan.

(5) The provisions of the site-specific monitoring plan must address the following items:

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

- (ii) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems.
  - (iii) Schedule for conducting initial and periodic performance evaluations.
  - (iv) Performance evaluation procedures and acceptance criteria (e.g., calibrations), including the quality control program in accordance with the general requirements of § 63.8(d).
  - (v) On-going operation and maintenance procedures, in accordance with the general requirements of §§ 63.8(c)(1)(ii), (c)(3), and (c)(4)(ii).
  - (vi) Conditions that define a CMS that is out of control consistent with § 63.8(c)(7)(i) where appropriate, and for responding to out of control periods consistent with §§ 63.8(c)(7)(ii) and (c)(8).
  - (vii) On-going recordkeeping and reporting procedures, in accordance with the general requirements of §§ 63.10(c), (e)(1), and (e)(2)(i), or as specifically required under this subpart.
- (e) As part of your demonstration of continuous compliance, you must perform periodic tune-ups of your EGU(s), according to § 63.10021(e).
- (f) Except as provided under paragraph (n) of this section, you are subject to the requirements of this subpart for at least 6 months following the last date you met the definition of an EGU subject to this subpart (e.g., 6 months after a cogeneration unit provided more than one third of its potential electrical output capacity and more than 25 megawatts electrical output to any power distributions system for sale). You may opt to remain subject to the provisions of this subpart beyond 6 months after the last date you met the definition of an EGU subject to this subpart, unless your unit is a solid waste incineration unit subject to standards under CAA section 129 (e.g., 40 CFR part 60, subpart CCCC (New Source Performance Standards (NSPS) for Commercial and Industrial Solid Waste Incineration Units, or subpart DDDD (Emissions Guidelines (EG) for Existing Commercial and Industrial Solid Waste Incineration Units). Notwithstanding the provisions of this subpart, an EGU that starts combusting solid waste is immediately subject to standards under CAA section 129 and the EGU remains subject to those standards until the EGU no longer meets the definition of a solid waste incineration unit consistent with the provisions of the applicable CAA section 129 standards.
- (g) Except as provided under paragraph (n) of this section, if your unit no longer meets the definition of an EGU subject to this subpart you must be in compliance with any newly applicable standards on the date you are no longer subject to this subpart. The date you are no longer subject to this subpart is a date selected by you, that must be at least 6 months from the date that your unit last met the definition of an EGU subject to this subpart or the date you begin combusting solid waste, consistent with § 63.9983(d). Your source must remain in compliance with this subpart until the date you select to cease complying with this subpart or the date you begin combusting solid waste, whichever is earlier.
- (h)
- (1) If you own or operate an EGU that does not meet the definition of an EGU subject to this subpart on April 16, 2015, and you commence or recommence operations that cause you to meet the definition of an EGU subject to this subpart, you are subject to the provisions of this subpart, including, but not limited to, the emission limitations and the monitoring requirements, as of the first day you meet the definition of an EGU subject to this subpart. You must complete all initial compliance demonstrations for this subpart applicable to your EGU within 180 days after you commence or recommence operations that cause you to meet the definition of an EGU subject to this subpart.
  - (2) You must provide 30 days prior notice of the date you intend to commence or recommence operations that cause you to meet the definition of an EGU subject to this subpart. The notification must identify:
    - (i) The name of the owner or operator of the EGU, the location of the facility, the unit(s) that will commence or recommence operations that will cause the unit(s) to meet the definition of an EGU subject to this subpart, and the date of the notice;

- (ii) The 40 CFR part 60, part 62, or part 63 subpart and subcategory currently applicable to your unit(s), and the subcategory of this subpart that will be applicable after you commence or recommence operation that will cause the unit(s) to meet the definition of an EGU subject to this subpart;
  - (iii) The date on which you became subject to the currently applicable emission limits;
  - (iv) The date upon which you will commence or recommence operations that will cause your unit to meet the definition of an EGU subject to this subpart, consistent with paragraph (f) of this section.
- (i)
- (1) If you own or operate an EGU subject to this subpart and cease to operate in a manner that causes your unit to meet the definition of an EGU subject to this subpart, you must be in compliance with any newly applicable section 112 or 129 standards on the date you selected consistent with paragraphs (g) and (n) of this section.
  - (2) You must provide 30 days prior notice of the date your EGU will cease complying with this subpart. The notification must identify:
    - (i) The name of the owner or operator of the EGU(s), the location of the facility, the EGU(s) that will cease complying with this subpart, and the date of the notice;
    - (ii) The currently applicable subcategory under this subpart, and any 40 CFR part 60, part 62, or part 63 subpart and subcategory that will be applicable after you cease complying with this subpart;
    - (iii) The date on which you became subject to this subpart;
    - (iv) The date upon which you will cease complying with this subpart, consistent with paragraph (g) of this section.
- (j) All air pollution control equipment necessary for compliance with any newly applicable emissions limits which apply as a result of the cessation or commencement or recommencement of operations that cause your EGU to meet the definition of an EGU subject to this subpart must be installed and operational as of the date your source ceases to be or becomes subject to this subpart.
- (k) All monitoring systems necessary for compliance with any newly applicable monitoring requirements which apply as a result of the cessation or commencement or recommencement of operations that cause your EGU to meet the definition of an EGU subject to this subpart must be installed and operational as of the date your source ceases to be or becomes subject to this subpart. All calibration and drift checks must be performed as of the date your source ceases to be or becomes subject to this subpart. You must also comply with provisions of §§ 63.10010, 63.10020, and 63.10021 of this subpart. Relative accuracy tests must be performed as of the performance test deadline for PM CEMS, if applicable. Relative accuracy testing for other CEMS need not be repeated if that testing was previously performed consistent with CAA section 112 monitoring requirements or monitoring requirements under this subpart.
- (l) On or before the date an EGU is subject to this subpart, you must install, certify, operate, maintain, and quality assure each monitoring system necessary for demonstrating compliance with the work practice standards for PM or non-mercury HAP metals during startup periods and shutdown periods. You must collect, record, report, and maintain data obtained from these monitoring systems during startup periods and shutdown periods.
- (m) Should you choose to rely on paragraph (2) of the definition of "startup" in § 63.10042 for your EGU, on or before the date your EGU is subject to this subpart, you must install, verify, operate, maintain, and quality assure each monitoring system necessary for demonstrating compliance with the work practice standards for PM or non-mercury HAP metals controls during startup periods and shutdown periods required to comply with § 63.10020(e).
- (1) You may rely on monitoring system specifications or instructions or manufacturer's specifications when installing, verifying, operating, maintaining, and quality assuring each monitoring system.

(2) You must collect, record, report, and maintain data obtained from these monitoring systems during startup periods and shutdown periods.

(n) If you have permanently converted your EGU from coal or oil to natural gas or biomass after your compliance date (or, if applicable, after your approved extended compliance date), as demonstrated by being subject to a permit provision or physical limitation (including retirement) that prevents you from operating in a manner that would subject you to this subpart, you are no longer subject to this subpart, notwithstanding the coal or oil usage in the previous calendar years. The date on which you are no longer subject to this subpart is the date on which you converted to natural gas or biomass firing; it is also the date on which you must be in compliance with any newly applicable standards.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23402, Apr. 19, 2012; 78 FR 24084, Apr. 24, 2013; 79 FR 68788, Nov. 19, 2014; 81 FR 20180, Apr. 6, 2016; 85 FR 55757, Sept. 9, 2020]

### § 63.10001 [Reserved]

### Testing and Initial Compliance Requirements

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

(a) **General requirements.** For each of your affected EGUs, you must demonstrate initial compliance with each applicable emissions limit in Table 1 or 2 of this subpart through performance testing. Where two emissions limits are specified for a particular pollutant (e.g., a heat input-based limit in lb/MMBtu and a gross output-based limit in lb/MWh), you may demonstrate compliance with either emission limit. For a particular compliance demonstration, you may be required to conduct one or more of the following activities in conjunction with performance testing: collection of data, e.g., hourly gross output data (megawatts); establishment of operating limits according to § 63.10011 and Tables 4 and 7 to this subpart; and CMS performance evaluations. In all cases, you must demonstrate initial compliance no later than the date in paragraph (f) of this section for tune-up work practices for existing EGUs; the date that compliance must be demonstrated, as given in § 63.9984 for other requirements for existing EGUs; and in paragraph (g) of this section for all requirements for new EGUs.

(1) To demonstrate initial compliance with an applicable emissions limit in Table 1 or 2 to this subpart using stack testing, the initial performance test generally consists of three runs at specified process operating conditions using approved methods. If you are required to establish operating limits (see paragraph (d) of this section and Table 4 to this subpart), you must collect all applicable parametric data during the performance test period. Also, if you choose to comply with an electrical output-based emission limit, you must collect hourly electrical load data during the test period.

(2) To demonstrate initial compliance using either a CMS that measures HAP concentrations directly (i.e., an Hg, HCl, or HF CEMS, or a sorbent trap monitoring system) or an SO<sub>2</sub> or PM CEMS, the initial performance test shall consist of 30- or, if applicable for Hg, 90-boiler operating days. If the CMS is certified prior to the compliance date (or, if applicable, the approved extended compliance date), the test shall begin with the first operating day on or after that date, except as otherwise provided in paragraph (b) of this section. If the CMS is not certified prior to the compliance date, the test shall begin with the first operating day after certification testing is successfully completed. In all cases, the initial 30- or 90- operating day averaging period must be completed on or before the date that compliance must be demonstrated (i.e., 180 days after the applicable compliance date).

(i) The CMS performance test must demonstrate compliance with the applicable Hg, HCl, HF, PM, or SO<sub>2</sub> emissions limit in Table 1 or 2 to this subpart.

(ii) You must collect hourly data from auxiliary monitoring systems (i.e., stack gas flow rate, CO<sub>2</sub>, O<sub>2</sub>, or moisture, as applicable) during the performance test period, in order to convert the pollutant concentrations to units of the standard. If you choose to comply with a gross output-based emission limit, you must also collect hourly gross output data during the performance test period.

(iii) For a group of affected units that are in the same subcategory, are subject to the same emission standards, and share a common stack, if you elect to demonstrate compliance by monitoring emissions at the common stack, startup and shutdown emissions (if any) that occur during the 30-(or, if applicable, 90-) boiler

operating day performance test must either be excluded from or included in the compliance demonstration as follows:

(A) If one of the units that shares the stack either starts up or shuts down at a time when none of the other units is operating, you must exclude all pollutant emission rates measured during the startup or shutdown period, unless you are using a sorbent trap monitoring system to measure Hg emissions and have elected to include startup and shutdown emissions in the compliance demonstrations;

(B) If all units that are currently operating are in the startup or shutdown mode, you must exclude all pollutant emission rates measured during the startup or shutdown period, unless you are using a sorbent trap monitoring system to measure Hg emissions and have elected to include startup and shutdown emissions in the compliance demonstrations; or

(C) If any unit starts up or shuts down at a time when another unit is operating, and the other unit is not in the startup or shutdown mode, you must include all pollutant emission rates measured during the startup or shutdown period in the compliance demonstrations.

(b) **Performance testing requirements.** If you choose to use performance testing to demonstrate initial compliance with the applicable emissions limits in Tables 1 and 2 to this subpart for your EGUs, you must conduct the tests according to 40 CFR 63.10007 and Table 5 to this subpart. Notwithstanding these requirements, when Table 5 specifies the use of isokinetic EPA test Method 5, 5D, 26A, or 29 for a stack test, if concurrent measurement of the stack gas flow rate or moisture content is needed to convert the pollutant concentrations to units of the standard, separate determination of these parameters using EPA test Method 2 or EPA test Method 4 is not necessary. Instead, the stack gas flow rate and moisture content can be determined from data that are collected during the EPA test Method 5, 5D, 6, 26A, or 29 test (e.g., pitot tube (delta P) readings, moisture collected in the impingers, etc.). For the purposes of the initial compliance demonstration, you may use test data and results from a performance test conducted prior to the date on which compliance is required as specified in 40 CFR 63.9984, provided that the following conditions are fully met:

(1) For a performance test based on stack test data, the test was conducted no more than 12 calendar months prior to the date on which compliance is required as specified in § 63.9984;

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

(3) The performance test was conducted in accordance with all applicable requirements in § 63.10007 and Table 5 to this subpart;

(4) A record of all parameters needed to convert pollutant concentrations to units of the emission standard (e.g., stack flow rate, diluent gas concentrations, hourly gross outputs) is available for the entire performance test period; and

(5) For each performance test based on stack test data, you certify, and keep documentation demonstrating, that the EGU configuration, control devices, and fuel(s) have remained consistent with conditions since the prior performance test was conducted.

(6) For performance stack test data that are collected prior to the date that compliance must be demonstrated and are used to demonstrate initial compliance with applicable emissions limits, the interval for subsequent stack tests begins on the date that compliance must be demonstrated.

(c) **Operating limits.** In accordance with § 63.10010 and Table 4 to this subpart, you may be required to establish operating limits using PM CPMS and using site-specific monitoring for certain liquid oil-fired units as part of your initial compliance demonstration.

(d) **CMS requirements.** If, for a particular emission or operating limit, you are required to (or elect to) demonstrate initial compliance using a continuous monitoring system, the CMS must pass a performance evaluation prior to the initial compliance demonstration. If a CMS has been previously certified under another state or federal program and is continuing to meet the on-going quality-assurance (QA) requirements of that program, then, provided that

the certification and QA provisions of that program meet the applicable requirements of §§ 63.10010(b) through (h), an additional performance evaluation of the CMS is not required under this subpart.

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

(2) For affected coal-fired or solid oil-derived fuel-fired EGUs that demonstrate compliance with the applicable emission limits for total non-mercury HAP metals, individual non-mercury HAP metals, total HAP metals, individual HAP metals, or filterable PM listed in Table 1 or 2 to this subpart using initial performance testing and continuous monitoring with PM CPMS:

(i) You must demonstrate initial compliance no later than the applicable date specified in § 63.9984(f) for existing EGUs and in paragraph (g) of this section for new EGUs.

(ii) You must demonstrate continuous compliance with the PM CPMS site-specific operating limit that corresponds to the results of the performance test demonstrating compliance with the emission limit with which you choose to comply.

(iii) You must repeat the performance test annually for the selected pollutant emissions limit and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(3) For affected EGUs that are either required to or elect to demonstrate initial compliance with the applicable Hg emission limit in Table 1 or 2 of this subpart using Hg CEMS or sorbent trap monitoring systems, initial compliance must be demonstrated no later than the applicable date specified in § 63.9984(f) for existing EGUs and in paragraph (g) of this section for new EGUs. Initial compliance is achieved if the arithmetic average of 30- (or 90-) boiler operating days of quality-assured CEMS (or sorbent trap monitoring system) data, expressed in units of the standard (see section 6.2 of appendix A to this subpart), meets the applicable Hg emission limit in Table 1 or 2 to this subpart.

(4) For affected liquid oil-fired EGUs that demonstrate compliance with the applicable emission limits for HCl or HF listed in Table 1 or 2 to this subpart using quarterly testing and continuous monitoring with a CMS:

(i) You must demonstrate initial compliance no later than the applicable date specified in § 63.9984(f) for existing EGUs and in paragraph (g) of this section for new EGUs.

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

(iii) You must repeat the performance test annually for the HCl or HF emissions limit and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(e) **Tune-ups.** All affected EGUs are subject to the work practice standards in Table 3 of this subpart. As part of your initial compliance demonstration, you must conduct a performance tune-up of your EGU according to § 63.10021(e).

(f) For an existing EGU without a neural network, a tune-up, following the procedures in § 63.10021(e), must occur within 6 months (180 days) after April 16, 2015. For an existing EGU with a neural network, a tune-up must occur within 18 months (545 days) after April 16, 2016. If a tune-up occurs prior to April 16, 2015, you must keep records showing that the tune-up met all rule requirements.



(g) If your new or reconstructed affected source commenced construction or reconstruction between May 3, 2011, and July 2, 2011, you must demonstrate initial compliance with either the proposed emission limits or the promulgated emission limits no later than 180 days after April 16, 2012 or within 180 days after startup of the source, whichever is later, according to § 63.7(a)(2)(ix).

(1) For the new or reconstructed affected source described in this paragraph (g), if you choose to comply with the proposed emission limits when demonstrating initial compliance, you must conduct a second compliance demonstration for the promulgated emission limits within 3 years after April 16, 2012 or within 3 years after startup of the affected source, whichever is later.

(2) If your new or reconstructed affected source commences construction or reconstruction after April 16, 2012, you must demonstrate initial compliance with the promulgated emission limits no later than 180 days after startup of the source.

(h) **Low emitting EGUs.** The provisions of this paragraph (h) apply to pollutants with emissions limits from new EGUs except Hg and to all pollutants with emissions limits from existing EGUs. You may pursue this compliance option unless prohibited pursuant to § 63.10000(c)(1)(i).

(1) An EGU may qualify for low emitting EGU (LEE) status for Hg, HCl, HF, filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals (or total HAP metals or individual HAP metals, for liquid oil-fired EGUs) if you collect performance test data that meet the requirements of this paragraph (h), and if those data demonstrate:

(i) For all pollutants except Hg, performance test emissions results less than 50 percent of the applicable emissions limits in Table 1 or 2 to this subpart for all required testing for 3 consecutive years; or

(ii) For Hg emissions from an existing EGU, either:

(A) Average emissions less than 10 percent of the applicable Hg emissions limit in Table 2 to this subpart (expressed either in units of lb/TBtu or lb/GWh); or

(B) Potential Hg mass emissions of 29.0 or fewer pounds per year and compliance with the applicable Hg emission limit in Table 2 to this subpart (expressed either in units of lb/TBtu or lb/GWh).

(2) For all pollutants except Hg, you must conduct all required performance tests described in § 63.10007 to demonstrate that a unit qualifies for LEE status.

(i) When conducting emissions testing to demonstrate LEE status, you must increase the minimum sample volume specified in Table 1 or 2 nominally by a factor of two.

(ii) Follow the instructions in § 63.10007(e) and Table 5 to this subpart to convert the test data to the units of the applicable standard.

(3) For Hg, you must conduct a 30- (or 90-) boiler operating day performance test using Method 30B in appendix A-8 to part 60 of this chapter to determine whether a unit qualifies for LEE status. Locate the Method 30B sampling probe tip at a point within 10 percent of the duct area centered about the duct's centroid at a location that meets Method 1 in appendix A-1 to part 60 of this chapter and conduct at least three nominally equal length test runs over the 30- (or 90-) boiler operating day test period. You may use a pair of sorbent traps to sample the stack gas for a period consistent with that given in section 5.2.1 of appendix A to this subpart. Collect Hg emissions data continuously over the entire test period (except when changing sorbent traps or performing required reference method QA procedures). As an alternative to constant rate sampling per Method 30B, you may use proportional sampling per section 8.2.2 of Performance Specification 12 B in appendix B to part 60 of this chapter.

(i) Depending on whether you intend to assess LEE status for Hg in terms of the lb/TBtu or lb/GWh emission limit in Table 2 to this subpart or in terms of the annual Hg mass emissions limit of 29.0 lb/year, you will have to collect some or all of the following data during the 30-boiler operating day test period (see paragraph (h)(3)(iii) of this section):

(A) Diluent gas (CO<sub>2</sub> or O<sub>2</sub>) data, using either Method 3A in appendix A–3 to part 60 of this chapter or a diluent gas monitor that has been certified according to part 75 of this chapter.

(B) Stack gas flow rate data, using either Method 2, 2F, or 2G in appendices A–1 and A–2 to part 60 of this chapter, or a flow rate monitor that has been certified according to part 75 of this chapter.

(C) Stack gas moisture content data, using either Method 4 in appendix A–1 to part 60 of this chapter, or a moisture monitoring system that has been certified according to part 75 of this chapter. Alternatively, an appropriate fuel-specific default moisture value from § 75.11(b) of this chapter may be used in the calculations or you may petition the Administrator under § 75.66 of this chapter for use of a default moisture value for non-coal-fired units.

(D) Hourly gross output data (megawatts), from facility records.

(ii) If you use CEMS to measure CO<sub>2</sub> (or O<sub>2</sub>) concentration, and/or flow rate, and/or moisture, record hourly average values of each parameter throughout the 30-boiler operating day test period. If you opt to use EPA reference methods rather than CEMS for any parameter, you must perform at least one representative test run on each operating day of the test period, using the applicable reference method.

(iii) Calculate the average Hg concentration, in µg/m<sup>3</sup> (dry basis), for each of LEE test runs comprising the 30- (or 90-) boiler operating day performance test, as the arithmetic average of all Method 30B sorbent trap results from the LEE test period. Also calculate, as applicable, the average values of CO<sub>2</sub> or O<sub>2</sub> concentration, stack gas flow rate, stack gas moisture content, and gross output for the LEE test period. Then:

(A) To express the test results in units of lb/TBtu, follow the procedures in § 63.10007(e). Use the average Hg concentration and diluent gas values in the calculations.

(B) To express the test results in units of lb/GWh, use Equations A–3 and A–4 in section 6.2.2 of appendix A to this subpart, replacing the hourly values “C<sub>h</sub>”, “Q<sub>h</sub>”, “B<sub>ws</sub>” and “(MW)<sub>h</sub>” with the average values of these parameters from the performance test.

(C) To calculate pounds of Hg per year, use one of the following methods:

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

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

(3) If an EGU has a federally-enforceable permit limit on either the annual heat input or the number of annual operating hours, you may modify the calculations in paragraph (h)(3)(iii)(C)(1) of this section by replacing the maximum potential annual heat input or 8,760 unit operating hours with the permit limit on annual heat input or operating hours (as applicable).

(4) For a group of affected units that vent to a common stack, you may either assess LEE status for the units individually by performing a separate emission test of each unit in the duct leading from the unit to the common stack, or you may perform a single emission test in the common stack. If you choose the common stack testing option, the units in the configuration qualify for LEE status if:

(i) The emission rate measured at the common stack is less than 50 percent (10 percent for Hg) of the applicable emission limit in Table 1 or 2 to this subpart; or

(ii) For Hg from an existing EGU, the applicable Hg emission limit in Table 2 to this subpart is met and the potential annual mass emissions, calculated according to paragraph (h)(3)(iii) of this section (with some modifications), are less than or equal to 29.0 pounds times the number of units sharing the common stack. Base your calculations on the combined heat input capacity of all units sharing the stack (*i.e.*, either the combined maximum rated value or, if applicable, a lower combined value restricted by permit conditions or operating hours).

(5) For an affected unit with a multiple stack or duct configuration in which the exhaust stacks or ducts are downstream of all emission control devices, you must perform a separate emission test in each stack or duct. The unit qualifies for LEE status if:

(i) The emission rate, based on all test runs performed at all of the stacks or ducts, is less than 50 percent (10 percent for Hg) of the applicable emission limit in Table 1 or 2 to this subpart; or

(ii) For Hg from an existing EGU, the applicable Hg emission limit in Table 2 to this subpart is met and the potential annual mass emissions, calculated according to paragraph (h)(3)(iii) of this section, are less than or equal to 29.0 pounds. Use the average Hg emission rate from paragraph (h)(5)(i) of this section in your calculations.

(i) **Liquid-oil fuel moisture measurement.** If your EGU combusts liquid fuels, if your fuel moisture content is no greater than 1.0 percent by weight, and if you would like to demonstrate initial and ongoing compliance with HCl and HF emissions limits, you must meet the requirements of paragraphs (i)(1) through (5) of this section.

(1) Measure fuel moisture content of each shipment of fuel if your fuel arrives on a batch basis; or

(2) Measure fuel moisture content daily if your fuel arrives on a continuous basis; or

(3) Obtain and maintain a fuel moisture certification from your fuel supplier.

(4) Use one of the following methods to determine fuel moisture content:

(i) ASTM D95–05 (Reapproved 2010), “Standard Test Method for Water in Petroleum Products and Bituminous Materials by Distillation,” or

(ii) ASTM D4006–11, “Standard Test Method for Water in Crude Oil by Distillation,” including Annex A1 and Appendix A1.

(5) Use one of the following methods to obtain fuel moisture samples:

(i) ASTM D4177–95 (Reapproved 2010), “Standard Practice for Automatic Sampling of Petroleum and Petroleum Products,” including Annexes A1 through A6 and Appendices X1 and X2, or

(ii) ASTM D4057–06 (Reapproved 2011), “Standard Practice for Manual Sampling of Petroleum and Petroleum Products,” including Annex A1.

(6) Should the moisture in your liquid fuel be more than 1.0 percent by weight, you must

(i) Conduct HCl and HF emissions testing quarterly (and monitor site-specific operating parameters as provided in § 63.10000(c)(2)(iii) or

(ii) Use an HCl CEMS and/or HF CEMS.

(j) Startup and shutdown for coal-fired or solid oil derived-fired units. You must follow the requirements given in Table 3 to this subpart.

(k) You must submit a Notification of Compliance Status summarizing the results of your initial compliance demonstration, as provided in § 63.10030.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23403, Apr. 19, 2012; 78 FR 24084, Apr. 24, 2013; 79 FR 68789, Nov. 19, 2014; 81 FR 20181, Apr. 6, 2016; 85 FR 55757, Sept. 9, 2020]

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

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

(b) For affected units meeting the LEE requirements of § 63.10005(h), you must repeat the performance test once every 3 years (once every year for Hg) according to Table 5 and § 63.10007. Should subsequent emissions testing results show the unit does not meet the LEE eligibility requirements, LEE status is lost. If this should occur:

(1) For all pollutant emission limits except for Hg, you must conduct emissions testing quarterly, except as otherwise provided in § 63.10021(d)(1).

(2) For Hg, you must install, certify, maintain, and operate a Hg CEMS or a sorbent trap monitoring system in accordance with appendix A to this subpart, within 6 calendar months of losing LEE eligibility. Until the Hg CEMS or sorbent trap monitoring system is installed, certified, and operating, you must conduct Hg emissions testing quarterly, except as otherwise provided in § 63.10021(d)(1). You must have 3 calendar years of testing and CEMS or sorbent trap monitoring system data that satisfy the LEE emissions criteria to reestablish LEE status.

(c) Except where paragraphs (a) or (b) of this section apply, or where you install, certify, and operate a PM CEMS to demonstrate compliance with a filterable PM emissions limit, for liquid oil-, solid oil-derived fuel-, coal-fired and IGCC EGUs, you must conduct all applicable periodic emissions tests for filterable PM, individual, or total HAP metals emissions according to Table 5 to this subpart, § 63.10007, and § 63.10000(c), except as otherwise provided in § 63.10021(d)(1).

(d) Except where paragraph (b) of this section applies, for solid oil-derived fuel- and coal-fired EGUs that do not use either an HCl CEMS to monitor compliance with the HCl limit or an SO<sub>2</sub> CEMS to monitor compliance with the alternate equivalent SO<sub>2</sub> emission limit, you must conduct all applicable periodic HCl emissions tests according to Table 5 to this subpart and § 63.10007 at least quarterly, except as otherwise provided in § 63.10021(d)(1).

(e) Except where paragraph (b) of this section applies, for liquid oil-fired EGUs without HCl CEMS, HF CEMS, or HCl and HF CEMS, you must conduct all applicable emissions tests for HCl, HF, or HCl and HF emissions according to Table 5 to this subpart and § 63.10007 at least quarterly, except as otherwise provided in § 63.10021(d)(1), and conduct site-specific monitoring under a plan as provided for in § 63.10000(c)(2)(iii).

**(f) *Time between performance tests.***

(1) Notwithstanding the provisions of § 63.10021(d)(1), the requirements listed in paragraphs (g) and (h) of this section, and the requirements of paragraph (f)(3) of this section, you must complete performance tests for your EGU as follows:

(i) At least 45 calendar days, measured from the test's end date, must separate performance tests conducted every quarter;

(ii) For annual testing:

(A) At least 320 calendar days, measured from the test's end date, must separate performance tests;

(B) At least 320 calendar days, measured from the test's end date, must separate annual sorbent trap mercury testing for 30-boiler operating day LEE tests;

(C) At least 230 calendar days, measured from the test's end date, must separate annual sorbent trap mercury testing for 90-boiler operating day LEE tests; and

(iii) At least 1,050 calendar days, measured from the test's end date, must separate performance tests conducted every 3 years.

(2) For units demonstrating compliance through quarterly emission testing, you must conduct a performance test in the 4th quarter of a calendar year if your EGU has skipped performance tests in the first 3 quarters of the calendar year.

(3) If your EGU misses a performance test deadline due to being inoperative and if 168 or more boiler operating hours occur in the next test period, you must complete an additional performance test in that period as follows:

(i) At least 15 calendar days must separate two performance tests conducted in the same quarter.

(ii) At least 107 calendar days must separate two performance tests conducted in the same calendar year.

(iii) At least 350 calendar days must separate two performance tests conducted in the same 3 year period.

(g) If you elect to demonstrate compliance using emissions averaging under § 63.10009, you must continue to conduct performance stack tests at the appropriate frequency given in section (c) through (f) of this section.

(h) If a performance test on a non-mercury LEE shows emissions in excess of 50 percent of the emission limit and if you choose to reapply for LEE status, you must conduct performance tests at the appropriate frequency given in section (c) through (e) of this section for that pollutant until all performance tests over a consecutive 3-year period show compliance with the LEE criteria.

(i) If you are required to meet an applicable tune-up work practice standard, you must conduct a performance tune-up according to § 63.10021(e).

(1) For EGUs not employing neural network combustion optimization during normal operation, each performance tune-up specified in § 63.10021(e) must be no more than 36 calendar months after the previous performance tune-up.

(2) For EGUs employing neural network combustion optimization systems during normal operation, each performance tune-up specified in § 63.10021(e) must be no more than 48 calendar months after the previous performance tune-up.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23403, Apr. 19, 2012; 78 FR 24085, Apr. 24, 2013; 81 FR 20182, Apr. 6, 2016]

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

(a) Except as otherwise provided in this section, you must conduct all required performance tests according to § 63.7(d), (e), (f), and (h). You must also develop a site-specific test plan according to the requirements in § 63.7(c).

(1) If you use CEMS (Hg, HCl, SO<sub>2</sub>, or other) to determine compliance with a 30- (or, if applicable, 90-) boiler operating day rolling average emission limit, you must collect quality- assured CEMS data for all unit operating conditions, including startup and shutdown (see § 63.10011(g) and Table 3 to this subpart), except as otherwise provided in § 63.10020(b). Emission rates determined during startup periods and shutdown periods (as defined in § 63.10042) are not to be included in the compliance determinations, except as otherwise provided in §§ 63.10000(c)(1)(vi)(B) and 63.10005(a)(2)(iii).

(2) If you conduct performance testing with test methods in lieu of continuous monitoring, operate the unit at maximum normal operating load conditions during each periodic (e.g., quarterly) performance test. Maximum

normal operating load will be generally between 90 and 110 percent of design capacity but should be representative of site specific normal operations during each test run.

(3) For establishing operating limits with particulate matter continuous parametric monitoring system (PM CPMS) to demonstrate compliance with a PM or non Hg metals emissions limit, operate the unit at maximum normal operating load conditions during the performance test period. Maximum normal operating load will be generally between 90 and 110 percent of design capacity but should be representative of site specific normal operations during each test run.

(b) You must conduct each performance test (including traditional 3-run stack tests, 30-boiler operating day tests based on CEMS data (or sorbent trap monitoring system data), and 30-boiler operating day Hg emission tests for LEE qualification) according to the requirements in Table 5 to this subpart.

(c) If you choose the filterable PM method to comply with the PM emission limit and demonstrate continuous performance using a PM CPMS as provided for in § 63.10000(c), you must also establish an operating limit according to § 63.10011(b), § 63.10023, and Tables 4 and 6 to this subpart. Should you desire to have operating limits that correspond to loads other than maximum normal operating load, you must conduct testing at those other loads to determine the additional operating limits.

(d) Except for a 30-boiler operating day performance test based on CEMS (or sorbent trap monitoring system) data, where the concept of test runs does not apply, you must conduct a minimum of three separate test runs for each performance test, as specified in § 63.7(e)(3). Each test run must comply with the minimum applicable sampling time or volume specified in Table 1 or 2 to this subpart. Sections 63.10005(d) and (h), respectively, provide special instructions for conducting performance tests based on CEMS or sorbent trap monitoring systems, and for conducting emission tests for LEE qualification.

(e) To use the results of performance testing to determine compliance with the applicable emission limits in Table 1 or 2 to this subpart, proceed as follows:

(1) Except for a 30-boiler operating day performance test based on CEMS (or sorbent trap monitoring system) data, if measurement results for any pollutant are reported as below the method detection level (e.g., laboratory analytical results for one or more sample components are below the method defined analytical detection level), you must use the method detection level as the measured emissions level for that pollutant in calculating compliance. The measured result for a multiple component analysis (e.g., analytical values for multiple Method 29 fractions both for individual HAP metals and for total HAP metals) may include a combination of method detection level data and analytical data reported above the method detection level.

(2) If the limits are expressed in lb/MMBtu or lb/TBtu, you must use the F-factor methodology and equations in sections 12.2 and 12.3 of EPA Method 19 in appendix A-7 to part 60 of this chapter. In cases where an appropriate F-factor is not listed in Table 19-2 of Method 19, you may use F-factors from Table 1 in section 3.3.5 of appendix F to part 75 of this chapter, or F-factors derived using the procedures in section 3.3.6 of appendix to part 75 of this chapter. Use the following factors to convert the pollutant concentrations measured during the initial performance tests to units of lb/scf, for use in the applicable Method 19 equations:

(i) Multiply SO<sub>2</sub> ppm by  $1.66 \times 10^{-7}$ ;

(ii) Multiply HCl ppm by  $9.43 \times 10^{-8}$ ;

(iii) Multiply HF ppm by  $5.18 \times 10^{-8}$ ;

(iv) Multiply HAP metals concentrations (mg/dscm) by  $6.24 \times 10^{-8}$ ; and

(v) Multiply Hg concentrations (µg/scm) by  $6.24 \times 10^{-11}$ .

(3) To determine compliance with emission limits expressed in lb/MWh or lb/GWh, you must first calculate the pollutant mass emission rate during the performance test, in units of lb/h. For Hg, if a CEMS or sorbent trap monitoring system is used, use Equation A-2 or A-3 in appendix A to this subpart (as applicable). In all other cases, use an equation that has the general form of Equation A-2 or A-3, replacing the value of K with  $1.66 \times$

$10^{-7}$  lb/scf-ppm for SO<sub>2</sub>,  $9.43 \times 10^{-8}$  lb/scf-ppm for HCl (if an HCl CEMS is used),  $5.18 \times 10^{-8}$  lb/scf-ppm for HF (if an HF CEMS is used), or  $6.24 \times 10^{-8}$  lb-scm/mg-scf for HAP metals and for HCl and HF (when performance stack testing is used), and defining C<sub>h</sub> as the average SO<sub>2</sub>, HCl, or HF concentration in ppm, or the average HAP metals concentration in mg/dscm. This calculation requires stack gas volumetric flow rate (scfh) and (in some cases) moisture content data (see §§ 63.10005(h)(3) and 63.10010). Then, if the applicable emission limit is in units of lb/GWh, use Equation A-4 in appendix A to this subpart to calculate the pollutant emission rate in lb/GWh. In this calculation, define (M)<sub>h</sub> as the calculated pollutant mass emission rate for the performance test (lb/h), and define (MW)<sub>h</sub> as the average electrical load during the performance test (megawatts). If the applicable emission limit is in lb/MWh rather than lb/GWh, omit the 10<sup>3</sup> term from Equation A-4 to determine the pollutant emission rate in lb/MWh.

(f) If you elect to (or are required to) use CEMS to continuously monitor Hg, HCl, HF, SO<sub>2</sub>, or PM emissions (or, if applicable, sorbent trap monitoring systems to continuously collect Hg emissions data), the following default values are available for use in the emission rate calculations during startup periods or shutdown periods (as defined in § 63.10042). For the purposes of this subpart, these default values are not considered to be substitute data.

(1) **Diluent cap values.** If you use CEMS (or, if applicable, sorbent trap monitoring systems) to comply with a heat input-based emission rate limit, you may use the following diluent cap values for a startup or shutdown hour in which the measured CO<sub>2</sub> concentration is below the cap value or the measured O<sub>2</sub> concentration is above the cap value:

(i) For an IGCC EGU, you may use 1% for CO<sub>2</sub> or 19% for O<sub>2</sub>.

(ii) For all other EGUs, you may use 5% for CO<sub>2</sub> or 14% for O<sub>2</sub>.

(2) **Default gross output.** If you use CEMS to continuously monitor Hg, HCl, HF, SO<sub>2</sub>, or PM emissions (or, if applicable, sorbent trap monitoring systems to continuously collect Hg emissions data), the following default value is available for use in the emission rate calculations during startup periods or shutdown periods (as defined in § 63.10042). For the purposes of this subpart, this default value is not considered to be substitute data. For a startup or shutdown hour in which there is heat input to an affected EGU but zero gross output, you must calculate the pollutant emission rate using a value equivalent to 5% of the maximum sustainable gross output, expressed in megawatts, as defined in section 6.5.2.1(a)(1) of appendix A to part 75 of this chapter. This default gross output is either the nameplate capacity of the EGU or the highest gross output observed in at least four representative quarters of EGU operation. For a monitored common stack, the default gross output is used only when all EGUs are operating (*i.e.*, combusting fuel) are in startup or shutdown mode, and have zero electrical generation. Under those conditions, a default gross output equal to 5% of the combined maximum sustainable gross output of the EGUs that are operating but have a total of zero gross output must be used to calculate the hourly gross output-based pollutant emissions rate.

(g) Upon request, you shall make available to the EPA Administrator such records as may be necessary to determine whether the performance tests have been done according to the requirements of this section.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23403, Apr. 19, 2012; 78 FR 24085, Apr. 24, 2013; 79 FR 68789, Nov. 19, 2014; 81 FR 20182, Apr. 6, 2016]

#### § 63.10008 [Reserved]

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

(a) **General eligibility.**

(1) You may use emissions averaging as described in paragraph (a)(2) of this section as an alternative to meeting the requirements of § 63.9991 for filterable PM, SO<sub>2</sub>, HF, HCl, non-Hg HAP metals, or Hg on an EGU-specific basis if:

(i) You have more than one existing EGU in the same subcategory located at one or more contiguous properties, belonging to a single major industrial grouping, which are under common control of the same person (or persons under common control); and

(ii) You use CEMS (or sorbent trap monitoring systems for determining Hg emissions) or quarterly emissions testing for demonstrating compliance.

(2) You may demonstrate compliance by emissions averaging among the existing EGUs in the same subcategory, if your averaged Hg emissions for EGUs in the “unit designed for coal  $\geq 8,300$  Btu/lb” subcategory are equal to or less than 1.2 lb/TBtu or  $1.3E-2$  lb/GWh on a 30-boiler operating day basis or if your averaged emissions of individual, other pollutants from other subcategories of such EGUs are equal to or less than the applicable emissions limit in Table 2 to this subpart, according to the procedures in this section. Note that except for the alternate Hg emissions limit from EGUs in the “unit designed for coal  $\geq 8,300$  Btu/lb” subcategory, the averaging time for emissions averaging for pollutants is 30-group boiler operating days (rolling daily) using data from CEMS and sorbent trap monitoring (for Hg), or a combination of data from CEMS and emissions testing (for other pollutants). The averaging time for emissions averaging for the alternate Hg limit (equal to or less than 1.0 lb/TBtu or  $1.1E-2$  lb/GWh) from EGUs in the “unit designed for coal  $\geq 8,300$  Btu/lb” subcategory is 90-group boiler operating days (rolling daily) using data from CEMS, sorbent trap monitoring, or a combination of data from CEMS and sorbent trap monitoring. For the purposes of this paragraph, 30- (or 90-) group boiler operating days is defined as a period during which at least one unit in the emissions averaging group operates on each of the 30 (or 90) days. You must calculate the weighted average emissions rate for the group in accordance with the procedures in this paragraph using the data from all units in the group including any that operate fewer than 30 (or 90) of the preceding 30- (or 90-) group boiler operating days.

(i) You may choose to have your EGU emissions averaging group meet either the heat input basis (MMBtu or TBtu, as appropriate for the pollutant) or gross output basis (MWh or GWh, as appropriate for the pollutant).

(ii) You may not mix bases within your EGU emissions averaging group.

(iii) You may use emissions averaging for affected units in different subcategories if the units vent to the atmosphere through a common stack (see paragraph (m) of this section).

(b) **Equations.** Use the following equations when performing calculations for your EGU emissions averaging group:

(1) **Group eligibility equations.**

$$WAER_m = \frac{[\sum_{j=1}^p Herm_j \times Rmm_j] + \sum_{k=1}^m Ter_k \times Rmt_k}{(\sum_{j=1}^p Rmm_j) + \sum_{k=1}^m Rmt_k} \quad (Eq. 1a)$$

Where:

$WAER_m$  = Maximum Weighted Average Emission Rate in terms of lb/heat input or lb/gross output,

$Herm_{i,j}$  = hourly emission rate (e.g., lb/MMBtu, lb/MWh) from CEMS or sorbent trap monitoring as determined during the initial compliance determination from EGU j,

$Rmm_j$  = Maximum rated heat input, MMBtu/h, or maximum rated gross output, MWh/h, for EGU j,

$p$  = number of EGUs in emissions averaging group that rely on CEMS,

$Ter_k$  = Emissions rate (lb/MMBTU or lb/MWh) as determined during the initial compliance determination of EGU k,

$Rmt_k$  = Maximum rated heat input, MMBtu/h, or maximum rated gross output, MWh/h, for EGU k, and

$m$  = number of EGUs in emissions averaging group that rely on emissions testing.



$$WAER_m = \frac{\sum \left[ \left( \sum_{j=1}^p Herm_{i,j} \right) \times Smm_j \times Cfm_j \right] + \sum_{k=1}^m Ter_k \times Smt_k \times Cft_k}{\sum \left[ \sum_{j=1}^p Smm_j \times Cfm_j \right] + \sum_{k=1}^m Smt_k \times Cft_k} \quad (Eq. 1b)$$

Where:

Variables with the similar names share the descriptions for Equation 1a of this section,

Smm<sub>j</sub> = maximum steam generation, lb<sub>steam</sub>/h or lb/gross output, for EGU j,

Cfm<sub>j</sub> = conversion factor, calculated from the most recent compliance test results, in terms units of heat output or gross output per pound of steam generated (MMBtu/lb<sub>steam</sub> or MWh/lb<sub>steam</sub>) from EGU j,

Smt<sub>k</sub> = maximum steam generation, lb<sub>steam</sub>/h or lb/gross output, for EGU k, and

Cfm<sub>k</sub> = conversion factor, calculated from the most recent compliance test results, in terms units of heat output or gross output per pound of steam generated (MMBtu/lb<sub>steam</sub> or MWh/lb<sub>steam</sub>) from EGU k.

(2) Weighted 30-boiler operating day rolling average emissions rate equations. Use Equation 2a or 2b of this section to calculate the 30 day rolling average emissions daily.

$$WAER = \frac{\sum_{i=1}^p \left[ \sum_{i=1}^n (Her_i \times Rm_i) \right]_p + \sum_{i=1}^m (Ter_i \times Rt_i)}{\sum_{i=1}^p \left[ \sum_{i=1}^n (Rm_i) \right]_p + \sum_{i=1}^m Rt_i} \quad (Eq. 2a)$$

Where:

Her<sub>i</sub> = hourly emission rate (e.g., lb/MMBtu, lb/MWh) from unit i's CEMS or sorbent trap monitoring system for the preceding 30-group boiler operating days,

Rm<sub>i</sub> = hourly heat input or gross output from unit i for the preceding 30-group boiler operating days,

p = number of EGUs in emissions averaging group that rely on CEMS or sorbent trap monitoring,

n = number of hours that hourly rates are collected over 30-group boiler operating days,

Ter<sub>i</sub> = Emissions rate from most recent emissions test of unit i in terms of lb/heat input or lb/gross output,

Rt<sub>i</sub> = Total heat input or gross output of unit i for the preceding 30-boiler operating days, and

m = number of EGUs in emissions averaging group that rely on emissions testing.

$$WAER = \frac{\sum_{i=1}^p \left[ \sum_{i=1}^n (Her_i \times Sm_i \times Cfm_i) \right]_p + \sum_{i=1}^m (Ter_i \times St_i \times Cft_i)}{\sum_{i=1}^p \left[ \sum_{i=1}^n (Sm_i \times Cfm_i) \right]_p + \sum_{i=1}^m St_i \times Cft_i} \quad (Eq. 2b)$$

Where:

variables with similar names share the descriptions for Equation 2a of this section,

$Sm_i$  = steam generation in units of pounds from unit  $i$  that uses CEMS for the preceding 30-group boiler operating days,

$Cfm_i$  = conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit  $i$  that uses CEMS from the preceding 30 group boiler operating days,

$St_i$  = steam generation in units of pounds from unit  $i$  that uses emissions testing, and

$Cft_i$  = conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit  $i$  that uses emissions testing.

(3) Weighted 90-boiler operating day rolling average emissions rate equations for Hg emissions from EGUs in the "coal-fired unit not low rank virgin coal" subcategory. Use Equation 3a or 3b of this section to calculate the 90-day rolling average emissions daily.

$$WAER = \frac{\sum_{i=1}^p \left[ \sum_{i=1}^n (Her_i \times Rm_i) \right]_p}{\sum_{i=1}^p \left[ \sum_{i=1}^n (Rm_i) \right]_p} \quad (\text{Eq. 3a})$$

Where:

$Her_i$  = Hourly emission rate from unit  $i$ 's Hg CEMS or Hg sorbent trap monitoring system for the preceding 90-group boiler operating days,

$Rm_i$  = Hourly heat input or gross output from unit  $i$  for the preceding 90-group boiler operating days,

$p$  = Number of EGUs in the emissions averaging group,

$n$  = Number of hours that hourly rates are collected over the 90-group boiler operating days.

$$WAER = \frac{\sum_{i=1}^p \left[ \sum_{i=1}^n (Her_i \times Sm_i \times Cfm_i) \right]_p}{\sum_{i=1}^p \left[ \sum_{i=1}^n (Sm_i \times Cfm_i) \right]_p} \quad (\text{Eq. 3b})$$

Where:

$Her_i$  = Hourly emission rate from unit  $i$ 's Hg CEMS or Hg sorbent trap monitoring system for the preceding 90-group boiler operating days,

$Sm_i$  = Steam generation in units of pounds from unit  $i$  that uses Hg CEMS or Hg sorbent trap monitoring for the preceding 90-group boiler operating days,

$Cfm_i$  = Conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit  $i$  that uses Hg CEMS or sorbent trap monitoring from the preceding 90-group boiler operating days,

$p$  = Number of EGUs in the emissions averaging group,

$n$  = Number of hours that hourly rates are collected over the 90-group boiler operating days.

(c) **Separate stack requirements.** For a group of two or more existing EGUs in the same subcategory that each vent to a separate stack, you may average filterable PM, SO<sub>2</sub>, HF, HCl, non-Hg HAP metals, or Hg emissions to demonstrate compliance with the limits in Table 2 to this subpart if you satisfy the requirements in paragraphs (d) through (j) of this section.

(d) For each existing EGU in the averaging group:

(1) The emissions rate achieved during the initial performance test for the HAP being averaged must not exceed the emissions level that was being achieved 180 days after April 16, 2015, or the date on which emissions testing done to support your emissions averaging plan is complete (if the Administrator does not require submission and approval of your emissions averaging plan), or the date that you begin emissions averaging, whichever is earlier; or

(2) The control technology employed during the initial performance test must not be less than the design efficiency of the emissions control technology employed 180 days after April 16, 2015 or the date that you begin emissions averaging, whichever is earlier.

(e) The weighted-average emissions rate from the existing EGUs participating in the emissions averaging option must be in compliance with the limits in Table 2 to this subpart at all times following the date that you begin emissions averaging.

(f) Emissions averaging group eligibility demonstration. You must demonstrate the ability for the EGUs included in the emissions averaging group to demonstrate initial compliance according to paragraph (f)(1) or (2) of this section using the maximum rated heat input or gross output over a 30- (or 90-) boiler operating day period of each EGU and the results of the initial performance tests. For this demonstration and prior to preparing your emissions averaging plan, you must conduct required emissions monitoring for 30- (or 90-) days of boiler operation and any required manual performance testing to calculate maximum weighted average emissions rate in accordance with this section. If, before the start of your initial compliance demonstration, the Administrator becomes aware that you intend to use emissions averaging for that demonstration, or if your initial Notification of Compliance Status (NOCS) indicates that you intend to implement emissions averaging at a future date, the Administrator may require you to submit your proposed emissions averaging plan and supporting data for approval. If the Administrator requires approval of your plan, you may not begin using emissions averaging until the Administrator approves your plan.

(1) You must use Equation 1a in paragraph (b) of this section to demonstrate that the maximum weighted average emissions rates of filterable PM, HF, SO<sub>2</sub>, HCl, non-Hg HAP metals, or Hg emissions from the existing units participating in the emissions averaging option do not exceed the emissions limits in Table 2 to this subpart.

(2) If you are not capable of monitoring heat input or gross output, and the EGU generates steam for purposes other than generating electricity, you may use Equation 1b of paragraph (b) of this section as an alternative to using Equation 1a of paragraph (b) of this section to demonstrate that the maximum weighted average emissions rates of filterable PM, HF, SO<sub>2</sub>, HCl, non-Hg HAP metals, or Hg emissions from the existing units participating in the emissions averaging group do not exceed the emission limits in Table 2 to this subpart.

(g) You must determine the weighted average emissions rate in units of the applicable emissions limit on a 30 group boiler operating day rolling average basis (or, if applicable, on a 90 group boiler operating day rolling average basis for Hg) according to paragraphs (g)(1) and (2) of this section. The first averaging period ends on the 30th (or, if applicable, 90th for the alternate Hg emission limit) group boiler operating day after the date that you begin emissions averaging.

(1) You must use Equation 2a or 3a of paragraph (b) of this section to calculate the weighted average emissions rate using the actual heat input or gross output for each existing unit participating in the emissions averaging option.

(2) If you are not capable of monitoring heat input or gross output, you may use Equation 2b or 3b of paragraph (b) of this section as an alternative to using Equation 2a of paragraph (b) of this section to calculate the average weighted emission rate using the actual steam generation from the units participating in the emissions averaging option.

(h) **CEMS (or sorbent trap monitoring) use.** If an EGU in your emissions averaging group uses CEMS (or a sorbent trap monitor for Hg emissions) to demonstrate compliance, you must use those data to determine the 30 (or 90) group boiler operating day rolling average emissions rate.

(i) **Emissions testing.** If you use manual emissions testing to demonstrate compliance for one or more EGUs in your emissions averaging group, you must use the results from the most recent performance test to determine the 30 (or 90) day rolling average. You may use CEMS or sorbent trap data in combination with data from the most recent manual performance test in calculating the 30 (or 90) group boiler operating day rolling average emissions rate.

(j) **Emissions averaging plan.** You must develop an implementation plan for emissions averaging according to the following procedures and requirements in paragraphs (j)(1) and (2) of this section.

(1) You must include the information contained in paragraphs (j)(1)(i) through (v) of this section in your implementation plan for all the emissions units included in an emissions averaging:

(i) The identification of all existing EGUs in the emissions averaging group, including for each either the applicable HAP emission level or the control technology installed as of 180 days after February 16, 2015, or the date on which you complete the emissions measurements used to support your emissions averaging plan (if the Administrator does not require submission and approval of your emissions averaging plan), or the date that you begin emissions averaging, whichever is earlier; and the date on which you are requesting emissions averaging to commence;

(ii) The process weighting parameter (heat input, gross output, or steam generated) that will be monitored for each averaging group;

(iii) The specific control technology or pollution prevention measure to be used for each emission EGU in the averaging group and the date of its installation or application. If the pollution prevention measure reduces or eliminates emissions from multiple EGUs, you must identify each EGU;

(iv) The means of measurement (e.g., CEMS, sorbent trap monitoring, manual performance test) of filterable PM, SO<sub>2</sub>, HF, HCl, individual or total non-Hg HAP metals, or Hg emissions in accordance with the requirements in § 63.10007 and to be used in the emissions averaging calculations; and

(v) A demonstration that emissions averaging can produce compliance with each of the applicable emission limit(s) in accordance with paragraph (b)(1) of this section.

(2) If, as described in paragraph (f) of this section, the Administrator requests you to submit the averaging plan for review and approval, you must receive approval before initiating emissions averaging.

(i) The Administrator shall use following criteria in reviewing and approving or disapproving the plan:

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

(B) Whether the plan presents information sufficient to determine that compliance will be achieved and maintained.

(ii) The Administrator shall not approve an emissions averaging implementation plan containing any of the following provisions:

(A) Any averaging between emissions of different pollutants or between units located at different facilities; or

(B) The inclusion of any emissions unit other than an existing unit in the same subcategory.

(k) **Common stack requirements.** For a group of two or more existing affected units, each of which vents through a single common stack, you may average emissions to demonstrate compliance with the limits in Table 2 to this subpart if you satisfy the requirements in paragraph (l) or (m) of this section.

(l) For a group of two or more existing units in the same subcategory and which vent through a common emissions control system to a common stack that does not receive emissions from units in other subcategories or categories, you may treat such averaging group as a single existing unit for purposes of this subpart and comply with the requirements of this subpart as if the group were a single unit.

(m) For all other groups of units subject to paragraph (k) of this section, you may elect to conduct manual performance tests according to procedures specified in § 63.10007 in the common stack. If emissions from affected units included in the emissions averaging and from other units not included in the emissions averaging (e.g., in a different subcategory) or other nonaffected units all vent to the common stack, you must shut down the units not included in the emissions averaging and the nonaffected units or vent their emissions to a different stack during the performance test. Alternatively, you may conduct a performance test of the combined emissions in the common stack with all units operating and show that the combined emissions meet the most stringent emissions limit. You may also use a CEMS or sorbent trap monitoring to apply this latter alternative to demonstrate that the combined emissions comply with the most stringent emissions limit on a continuous basis.

(n) Combination requirements. The common stack of a group of two or more existing EGUs in the same subcategory subject to paragraph (k) of this section may be treated as a single stack for purposes of paragraph (c) of this section and included in an emissions averaging group subject to paragraph (c) of this section.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23403, Apr. 19, 2012; 78 FR 24085, Apr. 24, 2013; 81 FR 20183, Apr. 6, 2016; 85 FR 55757, Sept. 9, 2020]

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

(a) Flue gases from the affected units under this subpart exhaust to the atmosphere through a variety of different configurations, including but not limited to individual stacks, a common stack configuration or a main stack plus a bypass stack. For the CEMS, PM CPMS, and sorbent trap monitoring systems used to provide data under this subpart, the continuous monitoring system installation requirements for these exhaust configurations are as follows:

(1) **Single unit-single stack configurations.** For an affected unit that exhausts to the atmosphere through a single, dedicated stack, you shall either install the required CEMS, PM CPMS, and sorbent trap monitoring systems in the stack or at a location in the ductwork downstream of all emissions control devices, where the pollutant and diluents concentrations are representative of the emissions that exit to the atmosphere.

(2) **Unit utilizing common stack with other affected unit(s).** When an affected unit utilizes a common stack with one or more other affected units, but no non-affected units, you shall either:

(i) Install the required CEMS, PM CPMS, and sorbent trap monitoring systems in the duct leading to the common stack from each unit; or

(ii) Install the required CEMS, PM CPMS, and sorbent trap monitoring systems in the common stack.

**(3) Unit(s) utilizing common stack with non-affected unit(s).**

(i) When one or more affected units shares a common stack with one or more non-affected units, you shall either:

(A) Install the required CEMS, PM CPMS, and sorbent trap monitoring systems in the ducts leading to the common stack from each affected unit; or

(B) Install the required CEMS, PM CPMS, and sorbent trap monitoring systems described in this section in the common stack and attribute all of the emissions measured at the common stack to the affected unit(s).

(ii) If you choose the common stack monitoring option:

(A) For each hour in which valid data are obtained for all parameters, you must calculate the pollutant emission rate and

(B) You must assign the calculated pollutant emission rate to each unit that shares the common stack.

**(4) Unit with a main stack and a bypass stack that exhausts to the atmosphere independent of the main stack.** If the exhaust configuration of an affected unit consists of a main stack and a bypass stack, you shall install CEMS on both the main stack and the bypass stack. If it is not feasible to certify and quality-assure the data from a monitoring system on the bypass stack, you shall:

(i) Route the exhaust from the bypass through the main stack and its monitoring so that bypass emissions are measured; or

(ii) Install a CEMS only on the main stack and count hours that the bypass stack is in use as hours of deviation from the monitoring requirements.

**(5) Unit with a common control device with multiple stack or duct configuration.** If the flue gases from an affected unit, which is configured such that emissions are controlled with a common control device or series of control devices, are discharged to the atmosphere through more than one stack or are fed into a single stack through two or more ducts, you may:

(i) Install required CEMS, PM CPMS, and sorbent trap monitoring systems in each of the multiple stacks;

(ii) Install required CEMS, PM CPMS, and sorbent trap monitoring systems in each of the ducts that feed into the stack;

(iii) Install required CEMS, PM CPMS, and sorbent trap monitoring systems in one of the multiple stacks or ducts and monitor the flows and dilution rates in all multiple stacks or ducts in order to determine total exhaust gas flow rate and pollutant mass emissions rate in accordance with the applicable limit; or

(iv) In the case of multiple ducts feeding into a single stack, install CEMS, PM CPMS, and sorbent trap monitoring systems in the single stack as described in paragraph (a)(1) of this section.

**(6) Unit with multiple parallel control devices with multiple stacks.** If the flue gases from an affected unit, which is configured such that emissions are controlled with multiple parallel control devices or multiple series of control devices are discharged to the atmosphere through more than one stack, you shall install the required CEMS, PM CPMS, and sorbent trap monitoring systems described in each of the multiple stacks. You shall calculate hourly flow-weighted average pollutant emission rates for the unit as follows:

(i) Calculate the pollutant emission rate at each stack or duct for each hour in which valid data are obtained for all parameters;

(ii) Multiply each calculated hourly pollutant emission rate at each stack or duct by the corresponding hourly stack gas flow rate at that stack or duct;

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

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

(b) If you use an oxygen (O<sub>2</sub>) or carbon dioxide (CO<sub>2</sub>) CEMS to convert measured pollutant concentrations to the units of the applicable emissions limit, the O<sub>2</sub> or CO<sub>2</sub> concentrations shall be monitored at a location that represents emissions to the atmosphere, *i.e.*, at the outlet of the EGU, downstream of all emission control devices. You must install, certify, maintain, and operate the CEMS according to part 75 of this chapter. Use only quality-assured O<sub>2</sub> or CO<sub>2</sub> data in the emissions calculations; do not use part 75 substitute data values.

(c) If you are required to use a stack gas flow rate monitor, either for routine operation of a sorbent trap monitoring system or to convert pollutant concentrations to units of an electrical output-based emission standard in Table 1 or 2 to this subpart, you must install, certify, operate, and maintain the monitoring system and conduct on-going quality-assurance testing of the system according to part 75 of this chapter. Use only unadjusted, quality-assured flow rate data in the emissions calculations. Do not apply bias adjustment factors to the flow rate data and do not use substitute flow rate data in the calculations.

(d) If you are required to make corrections for stack gas moisture content when converting pollutant concentrations to the units of an emission standard in Table 1 of 2 to this subpart, you must install, certify, operate, and maintain a moisture monitoring system in accordance with part 75 of this chapter. Alternatively, for coal-fired units, you may use appropriate fuel-specific default moisture values from § 75.11(b) of this chapter to estimate the moisture content of the stack gas or you may petition the Administrator under § 75.66 of this chapter for use of a default moisture value for non-coal-fired units. If you install and operate a moisture monitoring system, do not use substitute moisture data in the emissions calculations.

(e) If you use an HCl and/or HF CEMS, you must install, certify, operate, maintain, and quality-assure the data from the monitoring system in accordance with appendix B to this subpart. Calculate and record a 30-boiler operating day rolling average HCl or HF emission rate in the units of the standard, updated after each new boiler operating day. Each 30-boiler operating day rolling average emission rate is the average of all the valid hourly HCl or HF emission rates in the preceding 30 boiler operating days (see section 9.4 of appendix B to this subpart).

(f)

(1) If you use an SO<sub>2</sub> CEMS, you must install the monitor at the outlet of the EGU, downstream of all emission control devices, and you must certify, operate, and maintain the CEMS according to part 75 of this chapter.

(2) For on-going QA, the SO<sub>2</sub> CEMS must meet the applicable daily, quarterly, and semiannual or annual requirements in sections 2.1 through 2.3 of appendix B to part 75 of this chapter, with the following addition: You must perform the linearity checks required in section 2.2 of appendix B to part 75 of this chapter if the SO<sub>2</sub> CEMS has a span value of 30 ppm or less.

(3) Calculate and record a 30-boiler operating day rolling average SO<sub>2</sub> emission rate in the units of the standard, updated after each new boiler operating day. Each 30-boiler operating day rolling average emission rate is the average of all of the valid hourly SO<sub>2</sub> emission rates in the 30 boiler operating day period.

(4) Use only unadjusted, quality-assured SO<sub>2</sub> concentration values in the emissions calculations; do not apply bias adjustment factors to the part 75 SO<sub>2</sub> data and do not use part 75 substitute data values. For startup or shutdown hours (as defined in § 63.10042) the default gross output and the diluent cap are available for use in the hourly SO<sub>2</sub> emission rate calculations, as described in § 63.10007(f). Use a flag to identify each startup or shutdown hour and report a special code if the diluent cap or default gross output is used to calculate the SO<sub>2</sub> emission rate for any of these hours.

(g) If you use a Hg CEMS or a sorbent trap monitoring system, you must install, certify, operate, maintain and quality-assure the data from the monitoring system in accordance with appendix A to this subpart. You must

calculate and record a 30- (or, if alternate emissions averaging is used, 90-) boiler operating day rolling average Hg emission rate, in units of the standard, updated after each new boiler operating day. Each 30- (or, if alternate emissions averaging is used, 90-) boiler operating day rolling average emission rate, calculated according to section 6.2 of appendix A to the subpart, is the average of all of the valid hourly Hg emission rates in the preceding 30- (or, if alternate emissions averaging is used, a 90-) boiler operating days. Section 7.1.4.3 of appendix A to this subpart explains how to reduce sorbent trap monitoring system data to an hourly basis.

(h) If you use a PM CPMS to demonstrate continuous compliance with an operating limit, you must install, calibrate, maintain, and operate the PM CPMS and record the output of the system as specified in paragraphs (h)(1) through (5) of this section.

(1) Install, calibrate, operate, and maintain your PM CPMS according to the procedures in your approved site-specific monitoring plan developed in accordance with § 63.10000(d), and meet the requirements in paragraphs (h)(1)(i) through (iii) of this section.

(i) The operating principle of the PM CPMS must be based on in-stack or extractive light scatter, light scintillation, beta attenuation, or mass accumulation detection of the exhaust gas or representative sample. The reportable measurement output from the PM CPMS may be expressed as milliamps, stack concentration, or other raw data signal.

(ii) The PM CPMS must have a cycle time (*i.e.*, period required to complete sampling, measurement, and reporting for each measurement) no longer than 60 minutes.

(iii) The PM CPMS must be capable, at a minimum, of detecting and responding to particulate matter concentrations of 0.5 mg/acm.

(2) For a new unit, complete the initial PM CPMS performance evaluation no later than October 13, 2012 or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than October 13, 2015.

(3) Collect PM CPMS hourly average output data for all boiler operating hours except as indicated in paragraph (h)(5) of this section. Express the PM CPMS output as milliamps, PM concentration, or other raw data signal value.

(4) Calculate the arithmetic 30-boiler operating day rolling average of all of the hourly average PM CPMS output collected during all nonexempt boiler operating hours data (e.g., milliamps, PM concentration, raw data signal).

(5) You must collect data using the PM CPMS at all times the process unit is operating and at the intervals specified in paragraph (h)(1)(ii) of this section, except for required monitoring system quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments), and any scheduled maintenance as defined in your site-specific monitoring plan.

(6) You must use all the data collected during all boiler operating hours in assessing the compliance with your operating limit except:

(i) Any data recorded during periods of monitoring system malfunctions or repairs associated with monitoring system malfunctions. You must report any monitoring system malfunctions as deviations in your compliance reports under 40 CFR 63.10031(c) or (g) (as applicable);

(ii) Any data recorded during periods when the monitoring system is out-of-control (as specified in your site-specific monitoring plan), repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or quality control activities conducted during out-of-control periods. You must report any such periods as deviations in your compliance reports under 40 CFR 63.10031(c) or (g) (as applicable);

(iii) Any data recorded during required monitoring system quality assurance or quality control activities that temporarily interrupt the measurement of output data from the PM CPMS; and



(iv) Any data recorded during periods of startup or shutdown.

(7) You must record and report the results of PM CPMS system performance audits, in accordance with 40 CFR 63.10031(k). You must also record and make available upon request the dates and duration of periods from when the PM CPMS is out of control until completion of the corrective actions necessary to return the PM CPMS to operation consistent with your site-specific monitoring plan.

(i) If you choose to comply with the PM filterable emissions limit in lieu of metal HAP limits, you may choose to install, certify, operate, and maintain a PM CEMS and record and report the output of the PM CEMS as specified in paragraphs (i)(1) through (8) of this section. Compliance with the applicable PM emissions limit in Table 1 or 2 to this subpart is determined on a 30-boiler operating day rolling average basis.

(1) You must install and certify your PM CEMS according to section 4 of appendix C to this subpart.

(2) You must operate, maintain, and quality-assure the data from your PM CEMS according to section 5 of appendix C to this subpart.

(3) You must reduce the data from your PM CEMS to hourly averages in accordance with section 6.1 of appendix C to this subpart.

(4) You must collect data using the PM CEMS at all times the process unit is operating and at the intervals specified in paragraph (a) of this section, except for required monitoring system quality assurance or quality control activities and any scheduled maintenance as defined in your site-specific monitoring plan.

(j) You may choose to comply with the metal HAP emissions limits using CEMS approved in accordance with § 63.7(f) as an alternative to the performance test method specified in this rule. If approved to use a HAP metals CEMS, the compliance limit will be expressed as a 30-boiler operating day rolling average of the numerical emissions limit value applicable for your unit in tables 1 or 2. If approved, you may choose to install, certify, operate, and maintain a HAP metals CEMS and record the output of the HAP metals CEMS as specified in paragraphs (j)(1) through (5) of this section.

(1)

(i) Install, calibrate, operate, and maintain your HAP metals CEMS according to your CMS quality control program, as described in § 63.8(d)(2). The reportable measurement output from the HAP metals CEMS must be expressed in units of the applicable emissions limit (e.g., lb/MMBtu, lb/MWh) and in the form of a 30-boiler operating day rolling average.

(ii) Operate and maintain your HAP metals CEMS according to the procedures and criteria in your site specific performance evaluation and quality control program plan required in § 63.8(d).

(2) Collect HAP metals CEMS hourly average output data for all boiler operating hours except as indicated in section (j)(4) of this section.

(3) Calculate the arithmetic 30-boiler operating day rolling average of all of the hourly average HAP metals CEMS output data collected during all nonexempt boiler operating hours data.

(4) You must collect data using the HAP metals CEMS at all times the process unit is operating and at the intervals specified in paragraph (a) of this section, except for required monitoring system quality assurance or quality control activities, and any scheduled maintenance as defined in your site-specific monitoring plan.

(i) You must use all the data collected during all boiler operating hours in assessing the compliance with your emission limit except:

(A) Any data collected during periods of monitoring system malfunctions and repairs associated with monitoring system malfunctions. You must report any monitoring system malfunctions as deviations in your compliance reports under 40 CFR 63.10031(c) or (g) (as applicable);

(B) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or quality control activities conducted during out-of-control periods. You must report any out of control periods as deviations in your compliance reports under 40 CFR 63.10031(c) or (g) (as applicable);

(C) Any data recorded during required monitoring system quality assurance or quality control activities that temporarily interrupt the measurement of emissions (e.g., calibrations, certain audits, routine probe maintenance); and

(D) Any data recorded during periods of startup or shutdown.

(ii) You must record and report the results of HAP metals CEMS system performance audits, in accordance with 40 CFR 63.10031(k). You must also record and make available upon request the dates and duration of periods when the HAP metals CEMS is out of control to completion of the corrective actions necessary to return the HAP metals CEMS to operation consistent with your site-specific performance evaluation and quality control program plan.

(k) If you demonstrate compliance with the HCl and HF emission limits for a liquid oil-fired EGU by conducting quarterly testing, you must also develop a site-specific monitoring plan as provided for in § 63.10000(c)(2)(iii) and Table 7 to this subpart.

(l) Should you choose to rely on paragraph (2) of the definition of "startup" in § 63.10042 for your EGU, you must install, verify, operate, maintain, and quality assure each monitoring system necessary for demonstrating compliance with the PM or non-mercury metals work practice standards required to comply with § 63.10020(e).

(1) You shall develop a site-specific monitoring plan for PM or non-mercury metals work practice monitoring during startup periods.

(2) You shall submit the site-specific monitoring plan upon request by the Administrator.

(3) The provisions of the monitoring plan must address the following items:

(i) Monitoring system installation;

(ii) Performance and equipment specifications;

(iii) Schedule for initial and periodic performance evaluations;

(iv) Performance evaluation procedures and acceptance criteria;

(v) On-going operation and maintenance procedures; and

(vi) On-going recordkeeping and reporting procedures.

(4) You may rely on monitoring system specifications or instructions or manufacturer's specifications to address paragraphs (l)(3)(i) through (vi) of this section.

(5) You must operate and maintain the monitoring system according to the site-specific monitoring plan.

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

(a) You must demonstrate initial compliance with each emissions limit that applies to you by conducting performance testing.

(b) If you are subject to an operating limit in Table 4 to this subpart, you demonstrate initial compliance with HAP metals or filterable PM emission limit(s) through performance stack tests and you elect to use a PM CPMS to demonstrate continuous performance, or if, for a liquid oil-fired EGU, and you use quarterly stack testing for HCl and HF plus site-specific parameter monitoring to demonstrate continuous performance, you must also establish a site-specific operating limit, in accordance with § 63.10007 and Table 6 to this subpart. You may use only the parametric data recorded during successful performance tests (*i.e.*, tests that demonstrate compliance with the applicable emissions limits) to establish an operating limit.

(c)

(1) If you use CEMS or sorbent trap monitoring systems to measure a HAP (*e.g.*, Hg or HCl) directly, the initial performance test, shall consist of a 30-boiler operating day (or, for certain coal-fired, existing EGUs that use emissions averaging for Hg, a 90-boiler operating day) rolling average emissions rate obtained with a certified CEMS or sorbent trap system, expressed in units of the standard. If the monitoring system is certified prior to the applicable compliance date, the initial averaging period shall either begin with: The first boiler operating day on or after the compliance date; or 30 (or, if applicable, 90) boiler operating days prior to that date, as described in § 63.10005(b). In all cases, the initial 30- or 90-boiler operating day averaging period must be completed on or before the date that compliance must be demonstrated, in accordance with § 63.9984(f). Initial compliance is demonstrated if the results of the performance test meet the applicable emission limit in Table 1 or 2 to this subpart.

(2) For an EGU that uses a CEMS to measure SO<sub>2</sub> or PM emissions for initial compliance, the initial performance test shall consist of a 30-boiler operating day average emission rate obtained with certified CEMS, expressed in units of the standard. If the monitoring system is certified prior to the applicable compliance date, the initial averaging period shall either begin with: The first boiler operating day on or after the compliance date; or 30 boiler operating days prior to that date, as described in § 63.10005(b). In all cases, the initial 30- boiler operating day averaging period must be completed on or before the date that compliance must be demonstrated, in accordance with § 63.9984(f). Initial compliance is demonstrated if the results of the performance test meet the applicable SO<sub>2</sub> or PM emission limit in Table 1 or 2 to this subpart.

(d) For candidate LEE units, use the results of the performance testing described in § 63.10005(h) to determine initial compliance with the applicable emission limit(s) in Table 1 or 2 to this subpart and to determine whether the unit qualifies for LEE status.

(e) You must submit a Notification of Compliance Status in accordance with 40 CFR 63.10031(f)(4) or (h), as applicable, containing the results of the initial compliance demonstration, as specified in 40 CFR 63.10030(e).

(f)

(1) You must determine the fuel whose combustion produces the least uncontrolled emissions, *i.e.*, the cleanest fuel, either natural gas or distillate oil, that is available on site or accessible nearby for use during periods of startup or shutdown.

(2) Your cleanest fuel, either natural gas or distillate oil, for use during periods of startup or shutdown determination may take safety considerations into account.

(g) You must follow the startup or shutdown requirements as established in Table 3 to this subpart for each coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGU.

(1) You may use the diluent cap and default gross output values, as described in § 63.10007(f), during startup periods or shutdown periods.

(2) You must operate all CMS, collect data, calculate pollutant emission rates, and record data during startup periods or shutdown periods.

(3) You must report the emissions data recorded during startup and shutdown. If you are relying on paragraph (2) of the definition of startup in 40 CFR 63.10042, then for startup and shutdown incidents that occur on or prior to December 31, 2023, you must also report the applicable supplementary information in 40 CFR 63.10031(c)(5) in the semiannual compliance report. For startup and shutdown incidents that occur on or after January 1, 2024, you must provide the applicable information in 40 CFR 63.10031(c)(5)(ii) and 40 CFR 63.10020(e) quarterly, in PDF files, in accordance with 40 CFR 63.10031(i).

(4) If you choose to use paragraph (2) of the definition of "startup" in § 63.10042 and you find that you are unable to safely engage and operate your particulate matter (PM) control(s) within 1 hour of first firing of coal, residual oil, or solid oil-derived fuel, you may choose to rely on paragraph (1) of definition of "startup" in § 63.10042 or you may submit a request to use an alternative non-opacity emissions standard, as described below.

(i) As mentioned in § 63.6(g)(1), your request will be published in the Federal Register for notice and comment rulemaking. Until promulgation in the Federal Register of the final alternative non-opacity emission standard, you shall comply with paragraph (1) of the definition of "startup" in § 63.10042. You shall not implement the alternative non-opacity emissions standard until promulgation in the Federal Register of the final alternative non-opacity emission standard.

(ii) Your request need not address the items contained in § 63.6(g)(2).

(iii) Your request shall provide evidence of a documented manufacturer-identified safety issue.

(iv) Your request shall provide information to document that the PM control device is adequately designed and sized to meet the PM emission limit applicable to the EGU.

(v) In addition, your request shall contain documentation that:

(A) Your EGU is using clean fuels to the maximum extent possible, taking into account considerations such as not compromising boiler or control device integrity, to bring your EGU and PM control device up to the temperature necessary to alleviate or prevent the identified safety issues prior to the combustion of primary fuel in your EGU;

(B) You have followed explicitly your EGU manufacturer's procedures to alleviate or prevent the identified safety issue; and

(C) You have identified with specificity the details of your EGU manufacturer's statement of concern.

(vi) Your request shall specify the other work practice standards you will take to limit HAP emissions during startup periods and shutdown periods to ensure a control level consistent with the work practice standards of the final rule.

(vii) You must comply with all other work practice requirements, including but not limited to data collection, recordkeeping, and reporting requirements.

## Continuous Compliance Requirements

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

(a) You must monitor and collect data according to this section and the site-specific monitoring plan required by § 63.10000(d).

(b) You must operate the monitoring system and collect data at all required intervals at all times that the affected EGU is operating, except for required monitoring system quality assurance or quality control activities, including, as applicable, calibration checks and required zero and span adjustments, and any scheduled maintenance as defined in your site-specific monitoring plan. You are required to affect monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable.

(c) You may not use data recorded during EGU startup or shutdown in calculations used to report emissions, except as otherwise provided in §§ 63.10000(c)(1)(vi)(B) and 63.10005(a)(2)(iii). In addition, data recorded during monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, or required monitoring system quality assurance or control activities may not be used in calculations used to report emissions or operating levels. You must use all of the quality-assured data collected during all other periods in assessing the operation of the control device and associated control system.

(d) Periods of monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, and required monitoring system quality assurance or quality control activities excluding zero and span checks must be reported as time the monitor was inoperative (downtime) under 63.10(c). Failure to collect required quality-assured data during monitoring system malfunctions, monitoring system out-of-control periods, or repairs associated with monitoring system malfunctions or monitoring system out-of-control periods is a deviation from the monitoring requirements.

(e) Additional requirements during startup periods or shutdown periods if you choose to rely on paragraph (2) of the definition of "startup" in § 63.10042 for your EGU.

(1) During each period of startup, you must record for each EGU:

- (i) The date and time that clean fuels being combusted for the purpose of startup begins;
- (ii) The quantity and heat input of clean fuel for each hour of startup;
- (iii) The gross output for each hour of startup;
- (iv) The date and time that non-clean fuel combustion begins; and
- (v) The date and time that clean fuels being combusted for the purpose of startup ends.

(2) During each period of shutdown, you must record for each EGU:

- (i) The date and time that clean fuels being combusted for the purpose of shutdown begins;
- (ii) The quantity and heat input of clean fuel for each hour of shutdown;
- (iii) The gross output for each hour of shutdown;
- (iv) The date and time that non-clean fuel combustion ends; and
- (v) The date and time that clean fuels being combusted for the purpose of shutdown ends.

(3) For PM or non-mercury HAP metals work practice monitoring during startup periods, you must monitor and collect data according to this section and the site-specific monitoring plan required by § 63.10010(l).

(i) Except for an EGU that uses PM CEMS or PM CPMS to demonstrate compliance with the PM emissions limit, or that has LEE status for filterable PM or total non-Hg HAP metals for non-liquid oil-fired EGUs (or HAP metals emissions for liquid oil-fired EGUs), or individual non-mercury metals CEMS, you must:

(A) Record temperature and combustion air flow or calculated flow as determined from combustion equations of post-combustion (exhaust) gas, as well as amperage of forced draft fan(s), upstream of the filterable PM control devices during each hour of startup.

(B) Record temperature and flow of exhaust gas, as well as amperage of any induced draft fan(s), downstream of the filterable PM control devices during each hour of startup.

(C) For an EGU with an electrostatic precipitator, record the number of fields in service, as well as each field's secondary voltage and secondary current during each hour of startup.

(D) For an EGU with a fabric filter, record the number of compartments in service, as well as the differential pressure across the baghouse during each hour of startup.

(E) For an EGU with a wet scrubber needed for filterable PM control, record the scrubber liquid to flue gas ratio and the pressure drop across the scrubber during each hour of startup.

(ii) [Reserved]

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23404, Apr. 19, 2012; 79 FR 68790, Nov. 19, 2014; 81 FR 20187, Apr. 6, 2016; 85 FR 55759, Sept. 9, 2020]

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

(a) You must demonstrate continuous compliance with each emissions limit, operating limit, and work practice standard in Tables 1 through 4 to this subpart that applies to you, according to the monitoring specified in Tables 6 and 7 to this subpart and paragraphs (b) through (g) of this section.

(b) Except as otherwise provided in § 63.10020(c), if you use a CEMS to measure SO<sub>2</sub>, PM, HCl, HF, or Hg emissions, or using a sorbent trap monitoring system to measure Hg emissions, you must demonstrate continuous compliance by using all quality-assured hourly data recorded by the CEMS (or sorbent trap monitoring system) and the other required monitoring systems (e.g., flow rate, CO<sub>2</sub>, O<sub>2</sub>, or moisture systems) to calculate the arithmetic average emissions rate in units of the standard on a continuous 30-boiler operating day (or, if alternate emissions averaging is used for Hg, 90-boiler operating day) rolling average basis, updated at the end of each new boiler operating day. Use Equation 8 to determine the 30- (or, if applicable, 90-) boiler operating day rolling average.

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

Where:

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

(c) If you use a PM CPMS data to measure compliance with an operating limit in Table 4 to this subpart, you must record the PM CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected

by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (e.g., milliamps, PM concentration, raw data signal) on a 30 operating day rolling average basis, updated at the end of each new boiler operating day. Use Equation 9 to determine the 30 boiler operating day average.

$$30 \text{ boiler operating day average} = \frac{\sum_{i=1}^n Hpv_i}{n} \text{ (Eq. 9)}$$

Where:

$Hpv_i$  is the hourly parameter value for hour  $i$  and  $n$  is the number of valid hourly parameter values collected over 30 boiler operating days.

(1) For any exceedance of the 30-boiler operating day PM CPMS average value from the established operating parameter limit for an EGU subject to the emissions limits in Table 1 to this subpart, you must:

- (i) Within 48 hours of the exceedance, visually inspect the air pollution control device (APCD);
- (ii) If the inspection of the APCD identifies the cause of the exceedance, take corrective action as soon as possible, and return the PM CPMS measurement to within the established value; and
- (iii) Within 45 days of the exceedance or at the time of the annual compliance test, whichever comes first, conduct a PM emissions compliance test to determine compliance with the PM emissions limit and to verify or re-establish the CPMS operating limit. You are not required to conduct any additional testing for any exceedances that occur between the time of the original exceedance and the PM emissions compliance test required under this paragraph.

(2) PM CPMS exceedances of the operating limit for an EGU subject to the emissions limits in Table 1 of this subpart leading to more than four required performance tests in a 12-month period (rolling monthly) constitute a separate violation of this subpart.

(d) If you use quarterly performance testing to demonstrate compliance with one or more applicable emissions limits in Table 1 or 2 to this subpart, you

- (1) May skip performance testing in those quarters during which less than 168 boiler operating hours occur, except that a performance test must be conducted at least once every calendar year.
- (2) Must conduct the performance test as defined in Table 5 to this subpart and calculate the results of the testing in units of the applicable emissions standard; and
- (3) Must conduct site-specific monitoring using CMS to demonstrate compliance with the site-specific monitoring requirements in Table 7 to this subpart pertaining to HCl and HF emissions from a liquid oil-fired EGU to ensure compliance with the HCl and HF emission limits in Tables 1 and 2 to this subpart, in accordance with the requirements of § 63.10000(c)(2)(iii). The monitoring must meet the general operating requirements provided in § 63.10020.

(e) Conduct periodic performance tune-ups of your EGU(s), as specified in paragraphs (e)(1) through (9) of this section. For your first tune-up, you may perform the burner inspection any time prior to the tune-up or you may delay the first burner inspection until the next scheduled EGU outage provided you meet the requirements of § 63.10005. Subsequently, you must perform an inspection of the burner at least once every 36 calendar months unless your EGU employs neural network combustion optimization during normal operations in which case you must perform an inspection of the burner and combustion controls at least once every 48 calendar months. If your EGU is offline when a deadline to perform the tune-up passes, you shall perform the tune-up work practice requirements within 30 days after the re-start of the affected unit.

(1) As applicable, inspect the burner and combustion controls, and clean or replace any components of the burner or combustion controls as necessary upon initiation of the work practice program and at least once every required inspection period. Repair of a burner or combustion control component requiring special order parts may be scheduled as follows:

(i) Burner or combustion control component parts needing replacement that affect the ability to optimize NO<sub>x</sub> and CO must be installed within 3 calendar months after the burner inspection,

(ii) Burner or combustion control component parts that do not affect the ability to optimize NO<sub>x</sub> and CO may be installed on a schedule determined by the operator;

(2) As applicable, inspect the flame pattern and make any adjustments to the burner or combustion controls necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available, or in accordance with best combustion engineering practice for that burner type;

(3) As applicable, observe the damper operations as a function of mill and/or cyclone loadings, cyclone and pulverizer coal feeder loadings, or other pulverizer and coal mill performance parameters, making adjustments and effecting repair to dampers, controls, mills, pulverizers, cyclones, and sensors;

(4) As applicable, evaluate windbox pressures and air proportions, making adjustments and effecting repair to dampers, actuators, controls, and sensors;

(5) Inspect the system controlling the air-to-fuel ratio and ensure that it is correctly calibrated and functioning properly. Such inspection may include calibrating excess O<sub>2</sub> probes and/or sensors, adjusting overfire air systems, changing software parameters, and calibrating associated actuators and dampers to ensure that the systems are operated as designed. Any component out of calibration, in or near failure, or in a state that is likely to negate combustion optimization efforts prior to the next tune-up, should be corrected or repaired as necessary;

(6) Optimize combustion to minimize generation of CO and NO<sub>x</sub>. This optimization should be consistent with the manufacturer's specifications, if available, or best combustion engineering practice for the applicable burner type. NO<sub>x</sub> optimization includes burners, overfire air controls, concentric firing system improvements, neural network or combustion efficiency software, control systems calibrations, adjusting combustion zone temperature profiles, and add-on controls such as SCR and SNCR; CO optimization includes burners, overfire air controls, concentric firing system improvements, neural network or combustion efficiency software, control systems calibrations, and adjusting combustion zone temperature profiles;

(7) While operating at full load or the predominantly operated load, measure the concentration in the effluent stream of CO and NO<sub>x</sub> in ppm, by volume, and oxygen in volume percent, before and after the tune-up adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). You may use portable CO, NO<sub>x</sub> and O<sub>2</sub> monitors for this measurement. EGU's employing neural network optimization systems need only provide a single pre- and post-tune-up value rather than continual values before and after each optimization adjustment made by the system;

(8) Maintain on-site and submit, if requested by the Administrator, an annual report containing the information in paragraphs (e)(1) through (e)(9) of this section including:

(i) The concentrations of CO and NO<sub>x</sub> in the effluent stream in ppm by volume, and oxygen in volume percent, measured before and after an adjustment of the EGU combustion systems;

(ii) A description of any corrective actions taken as a part of the combustion adjustment; and

(iii) The type(s) and amount(s) of fuel used over the 12 calendar months prior to an adjustment, but only if the unit was physically and legally capable of using more than one type of fuel during that period; and

(9) Prior to January 1, 2024, report the tune-up date electronically, in a PDF file, in your semiannual compliance report, as specified in 40 CFR 63.10031(f)(4) and (6) and, if requested by the Administrator, in hard copy, as specified in 40 CFR 63.10031(f)(5). On and after January 1, 2024, report the tune-up date electronically in your



quarterly compliance report, in accordance with 40 CFR 63.10031(g) and section 10.2 of appendix E to this subpart. The tune-up report date is the date when tune-up requirements in paragraphs (e)(6) and (7) of this section are completed.

(f) You must submit the applicable reports and notifications required under 40 CFR 63.10031(a) through (k) to the Administrator electronically, using EPA's Emissions Collection and Monitoring Plan System (ECMPS) Client Tool. If the final date of any time period (or any deadline) for any of these submissions falls on a weekend or a Federal holiday, the time period shall be extended to the next business day. Moreover, if the EPA Host System supporting the ECMPS Client Tool is offline and unavailable for submission of reports for any part of a day when a report would otherwise be due, the deadline for reporting is automatically extended until the first business day on which the system becomes available following the outage. Use of the ECMPS Client Tool to submit a report or notification required under this subpart satisfies any requirement under subpart A of this part to submit that same report or notification (or the information contained in it) to the appropriate EPA Regional office or state agency whose delegation request has been approved.

(g) You must report each instance in which you did not meet an applicable emissions limit or operating limit in Tables 1 through 4 to this subpart or failed to conduct a required tune-up. These instances are deviations from the requirements of this subpart. These deviations must be reported according to § 63.10031.

(h) You must follow the startup or shutdown requirements as given in Table 3 to this subpart for each coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGU.

(1) You may use the diluent cap and default gross output values, as described in § 63.10007(f), during startup periods or shutdown periods.

(2) You must operate all CMS, collect data, calculate pollutant emission rates, and record data during startup periods or shutdown periods.

(3) [Reserved]

(4) You may choose to submit an alternative non-opacity emission standard, in accordance with the requirements contained in § 63.10011(g)(4). Until promulgation in the Federal Register of the final alternative non-opacity emission standard, you shall comply with paragraph (1) of the definition of "startup" in § 63.10042.

(i) If you are relying on paragraph 2 of the definition of startup in 40 CFR 63.10042, you must provide reports concerning activities and periods of startup and shutdown that occur on or prior to January 1, 2024, in accordance with 40 CFR 63.10031(c)(5), in your semiannual compliance report. For startup and shutdown incidents that occur on and after January 1, 2024, you must provide the applicable information referenced in 40 CFR 63.10031(c)(5)(ii) and 40 CFR 63.10020(e) quarterly, in PDF files, in accordance with 40 CFR 63.10031(i).

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23404, Apr. 19, 2012; 78 FR 24086, Apr. 24, 2013; 79 FR 68791, Nov. 19, 2014; 81 FR 20187, Apr. 6, 2016; 82 FR 16739, Apr. 6, 2017; 83 FR 30883, July 2, 2018; 85 FR 55759, Sept. 9, 2020]

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

(a) Following the compliance date, the owner or operator must demonstrate compliance with this subpart on a continuous basis by meeting the requirements of paragraphs (a)(1) through (4) of this section.

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

(2) For each existing unit participating in the emissions averaging option that is equipped with PM CPMS, maintain the average parameter value at or below the operating limit established during the most recent performance test;

(3) For each existing unit participating in the emissions averaging option venting to a common stack configuration containing affected units from other subcategories, maintain the appropriate operating limit for each unit as specified in Table 4 to this subpart that applies.

(4) For each existing EGU participating in the emissions averaging option, operate in accordance with the startup or shutdown work practice requirements given in Table 3 to this subpart.

(b) Any instance where the owner or operator fails to comply with the continuous monitoring requirements in paragraphs (a)(1) through (3) of this section is a deviation.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23404, Apr. 19, 2012; 79 FR 68791, Nov. 19, 2014]

**§ 63.10023 How do I establish my PM CPMS operating limit and determine compliance with it?**

(a) During the initial performance test or any such subsequent performance test that demonstrates compliance with the filterable PM, individual non-mercury HAP metals, or total non-mercury HAP metals limit (or for liquid oil-fired units, individual HAP metals or total HAP metals limit, including Hg) in Table 1 or 2, record all hourly average output values (e.g., milliamps, stack concentration, or other raw data signal) from the PM CPMS for the periods corresponding to the test runs (e.g., nine 1-hour average PM CPMS output values for three 3-hour test runs).

(b) Determine your operating limit as provided in paragraph (b)(1) or (b)(2) of this section. You must verify an existing or establish a new operating limit after each repeated performance test.

(1) [Reserved]

(2) Determine your operating limit as follows:

(i) If your PM performance test demonstrates your PM emissions do not exceed 75 percent of your emissions limit, you will use the average PM CPMS value recorded during the PM compliance test, the milliamp equivalent of zero output from your PM CPMS, and the average PM result of your compliance test to establish your operating limit. Calculate the operating limit by establishing a relationship of PM CPMS signal to PM concentration using the PM CPMS instrument zero, the average PM CPMS values corresponding to the three compliance test runs, and the average PM concentration from the Method 5 compliance test with the procedures in (b)(2)(i)(A) through (D) of this section.

(A) Determine your PM CPMS instrument zero output with one of the following procedures.

(1) Zero point data for in-situ instruments should be obtained by removing the instrument from the stack and monitoring ambient air on a test bench.

(2) Zero point data for extractive instruments should be obtained by removing the extractive probe from the stack and drawing in clean ambient air.

(3) The zero point can also be obtained by performing manual reference method measurements when the flue gas is free of PM emissions or contains very low PM concentrations (e.g., when your process is not operating, but the fans are operating or your source is combusting only natural gas) and plotting these with the compliance data to find the zero intercept.

(4) If none of the steps in paragraphs (A)(1) through (3) of this section are possible, you must use a zero output value provided by the manufacturer.

(B) Determine your PM CPMS instrument average ( $x$ ) in milliamps, and the average of your corresponding three PM compliance test runs ( $y$ ), using equation 10.

$$\bar{x} = \frac{1}{n} \sum_{i=1}^n X_i, \bar{y} = \frac{1}{n} \sum_{i=1}^n Y_i \quad (\text{Eq. 10})$$

Where:

$X_i$  = the PM CPMS data points for run  $i$  of the performance test,

$Y_i$  = the PM emissions value (in lb/MWh) for run  $i$  of the performance test, and

$n$  = the number of data points.

(C) With your PM CPMS instrument zero expressed in milliamps, your three run average PM CPMS milliamp value, and your three run average PM emissions value (in lb/MWh) from your compliance runs, determine a relationship of PM lb/MWh per milliamp with equation 11.

$$R = \frac{y}{(x - z)} \quad (\text{Eq. 11})$$

Where:

$R$  = the relative PM lb/MWh per milliamp for your PM CPMS,

$\bar{y}$  = the three run average PM lb/MWh,

$\bar{x}$  = the three run average milliamp output from your PM CPMS, and

$z$  = the milliamp equivalent of your instrument zero determined from (b)(2)(i)(A) of this section.

(D) Determine your source specific 30-day rolling average operating limit using the PM lb/MWh per milliamp value from equation 11 in equation 12, below. This sets your operating limit at the PM CPMS output value corresponding to 75 percent of your emission limit.

$$O_L = z + \frac{(0.75 \times L)}{R} \quad (\text{Eq. 12})$$

Where:

$O_L$  = the operating limit for your PM CPMS on a 30-day rolling average, in milliamps,

$L$  = your source PM emissions limit in lb/MWh,

$z$  = your instrument zero in milliamps, determined from (b)(2)(i)(A) of this section, and

R = the relative PM lb/MWh per milliamp for your PM CPMS, from equation 11.

(ii) If your PM compliance test demonstrates your PM emissions exceed 75 percent of your emissions limit, you will use the average PM CPMS value recorded during the PM compliance test demonstrating compliance with the PM limit to establish your operating limit.

(A) Determine your operating limit by averaging the PM CPMS milliamp output corresponding to your three PM performance test runs that demonstrate compliance with the emission limit using equation 13.

$$O_h = \frac{1}{n} \sum_{i=1}^n X_i \quad (\text{Eq. 13})$$

Where:

$X_i$  = the PM CPMS data points for all runs  $i$ ,

$n$  = the number of data points, and

$O_h$  = your site specific operating limit, in milliamps.

(iii) Your PM CPMS must provide a 4–20 milliamp output and the establishment of its relationship to manual reference method measurements must be determined in units of milliamps.

(iv) Your PM CPMS operating range must be capable of reading PM concentrations from zero to a level equivalent to two times your allowable emission limit. If your PM CPMS is an auto-ranging instrument capable of multiple scales, the primary range of the instrument must be capable of reading PM concentration from zero to a level equivalent to two times your allowable emission limit.

(v) During the initial performance test or any such subsequent performance test that demonstrates compliance with the PM limit, record and average all milliamp output values from the PM CPMS for the periods corresponding to the compliance test runs.

(vi) For PM performance test reports used to set a PM CPMS operating limit, the electronic submission of the test report must also include the make and model of the PM CPMS instrument, serial number of the instrument, analytical principle of the instrument (e.g. beta attenuation), span of the instruments primary analytical range, milliamp value equivalent to the instrument zero output, technique by which this zero value was determined, and the average milliamp signal corresponding to each PM compliance test run.

(c) You must operate and maintain your process and control equipment such that the 30 operating day average PM CPMS output does not exceed the operating limit determined in paragraphs (a) and (b) of this section.

[77 FR 9464, Feb. 16, 2012, as amended at 78 FR 24086, Apr. 24, 2013; 81 FR 20187, Apr. 6, 2016]

## Notification, Reports, and Records

### § 63.10030 What notifications must I submit and when?

(a) You must submit all of the notifications in §§ 63.7(b) and (c), 63.8 (e), (f)(4) and (6), and 63.9 (b) through (h) that apply to you by the dates specified.

(b) As specified in § 63.9(b)(2), if you startup your EGU that is an affected source before April 16, 2012, you must submit an Initial Notification not later than 120 days after April 16, 2012.

(c) As specified in § 63.9(b)(4) and (b)(5), if you startup your new or reconstructed EGU that is an affected source on or after April 16, 2012, you must submit an Initial Notification not later than 15 days after the actual date of startup of the EGU that is an affected source.

(d) When you are required to conduct a performance test, you must submit a Notification of Intent to conduct a performance test at least 30 days before the performance test is scheduled to begin.

(e) When you are required to conduct an initial compliance demonstration as specified in § 63.10011(a), you must submit a Notification of Compliance Status according to § 63.9(h)(2)(ii). The Notification of Compliance Status report must contain all of the information specified in paragraphs (e)(1) through (8) of this section, that applies to your initial compliance strategy.

(1) A description of the affected source(s), including identification of the subcategory of the source, the design capacity of the source, a description of the add-on controls used on the source, description of the fuel(s) burned, including whether the fuel(s) were determined by you or EPA through a petition process to be a non-waste under 40 CFR 241.3, whether the fuel(s) were processed from discarded non-hazardous secondary materials within the meaning of 40 CFR 241.3, and justification for the selection of fuel(s) burned during the performance test.

(2) Summary of the results of all performance tests and fuel analyses and calculations conducted to demonstrate initial compliance including all established operating limits.

(3) Identification of whether you plan to demonstrate compliance with each applicable emission limit through performance testing; fuel moisture analyses; performance testing with operating limits (e.g., use of PM CPMS); CEMS; or a sorbent trap monitoring system.

(4) Identification of whether you plan to demonstrate compliance by emissions averaging.

(5) A signed certification that you have met all applicable emission limits and work practice standards.

(6) If you had a deviation from any emission limit, work practice standard, or operating limit, you must also submit a brief description of the deviation, the duration of the deviation, emissions point identification, and the cause of the deviation in the Notification of Compliance Status report.

(7) Except for requests to switch from one emission limit to another, as provided in paragraph (e)(7)(iii) of this section, your initial notification of compliance status shall also include the following information:

(i) [Reserved]

(ii) Certifications of compliance, as applicable, and must be signed by a responsible official stating:

(A) "This EGU complies with the requirements in § 63.10021(a) to demonstrate continuous compliance." and

(B) "No secondary materials that are solid waste were combusted in any affected unit."

(iii) For each of your existing EGUs, identification of each emissions limit specified in Table 2 to this subpart with which you plan to comply initially. (*Note:* If, at some future date, you wish to switch from the limit specified

in your initial notification of compliance status, you must follow the procedures and meet the conditions of paragraphs (e)(7)(iii)(A) through (C) of this section).

(A) You may switch from a mass per heat input to a mass per gross output limit (or vice-versa), provided that:

(1) You submit a request that identifies for each EGU or EGU emissions averaging group involved in the proposed switch both the current and proposed emission limit;

(2) Your request arrives to the Administrator at least 30 calendar days prior to the date that the switch is proposed to occur;

(3) Your request includes performance stack test results or valid CMS data, obtained within 45 days prior to the date of your submission, demonstrating that each EGU or EGU emissions averaging group is in compliance with both the mass per heat input limit and the mass per gross output limit;

(4) You revise and submit all other applicable plans, e.g., monitoring and emissions averaging, with your request; and

(5) You maintain records of all information regarding your choice of emission limits.

(B) You must begin to use the revised emission limits starting in the next reporting period, after receipt of written acknowledgement from the Administrator of the switch.

(C) From submission of your request until start of the next reporting period after receipt of written acknowledgement from the Administrator of the switch, you must demonstrate compliance with both the mass per heat input and mass per gross output emission limits for each pollutant for each EGU or EGU emissions averaging group.

(8) Identification of whether you plan to rely on paragraph (1) or (2) of the definition of "startup" in § 63.10042.

(i) Should you choose to rely on paragraph (2) of the definition of "startup" in § 63.10042 for your EGU, you shall include a report that identifies:

(A) The original EGU installation date;

(B) The original EGU design characteristics, including, but not limited to, fuel mix and PM controls;

(C) Each design PM control device efficiency established during performance testing or while operating in periods other than startup and shutdown periods;

(D) The design PM emission rate from the EGU in terms of pounds PM per MMBtu and pounds PM per hour established during performance testing or while operating in periods other than startup and shutdown periods;

(E) The design time from start of fuel combustion to necessary conditions for each PM control device startup;

(F) Each design PM control device efficiency upon startup of the PM control device, if different from the efficiency provided in paragraph (e)(8)(i)(C) of this section;

(G) Current EGU PM producing characteristics, including, but not limited to, fuel mix and PM controls, if different from the characteristics provided in paragraph (e)(8)(i)(B) of this section;

(H) Current PM control device efficiency from each PM control device, if different from the efficiency provided in paragraph (e)(8)(i)(C) of this section;

(I) Current PM emission rate from the EGU in terms of pounds PM per MMBtu and pounds per hour, if different from the rate provided in paragraph (e)(8)(i)(D) of this section;

(J) Current time from start of fuel combustion to conditions necessary for each PM control device startup, if different from the time provided in paragraph (e)(8)(i)(E) of this section; and

(K) Current PM control device efficiency upon startup of each PM control device, if different from the efficiency provided in paragraph (e)(8)(i)(H) of this section.

(ii) The report shall be prepared, signed, and sealed by a professional engineer licensed in the state where your EGU is located.

(iii) You may switch from paragraph (1) of the definition of "startup" in § 63.10042 to paragraph (2) of the definition of "startup" (or vice-versa), provided that:

(A) You submit a request that identifies for each EGU or EGU emissions averaging group involved in the proposed switch both the current definition of "startup" relied on and the proposed definition you plan to rely on;

(B) Your request arrives to the Administrator at least 30 calendar days prior to the date that the switch is proposed to occur;

(C) You revise and submit all other applicable plans, e.g., monitoring and emissions averaging, with your submission;

(D) You maintain records of all information regarding your choice of the definition of "startup"; and

(E) You begin to use the revised definition of "startup" in the next reporting period after receipt of written acknowledgement from the Administrator of the switch.

(f) You must submit the notifications in § 63.10000(h)(2) and (i)(2) that may apply to you by the dates specified.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23404, Apr. 19, 2012; 78 FR 24087, Apr. 24, 2013; 79 FR 68791, Nov. 19, 2014; 81 FR 20187, Apr. 6, 2016; 85 FR 55760, Sept. 9, 2020]

### **§ 63.10031 What reports must I submit and when?**

(a) You must submit each report in this section that applies to you.

(1) If you are required to (or elect to) monitor Hg emissions continuously, you must meet the electronic reporting requirements of appendix A to this subpart.

(2) If you elect to monitor HCl and/or HF emissions continuously, you must meet the electronic reporting requirements of appendix B to this subpart. Notwithstanding this requirement, if you opt to certify your HCl monitor according to Performance Specification 18 in appendix B to part 60 of this chapter and to use Procedure 6 in appendix F to part 60 of this chapter for on-going QA of the monitor, then, on and prior to December 31, 2023, report only hourly HCl emissions data and the results of daily calibration drift tests and relative accuracy test audits (RATAs) performed on or prior to that date; keep records of all of the other required certification and QA tests and report them, starting in 2024.

(3) If you elect to monitor filterable PM emissions continuously, you must meet the electronic reporting requirements of appendix C to this subpart. Electronic reporting of hourly PM emissions data shall begin with the later of the first operating hour on or after January 1, 2024; or the first operating hour after completion of the initial PM CEMS correlation test.

(4) If you elect to demonstrate continuous compliance using a PM CPMS, you must meet the electronic reporting requirements of appendix D to this subpart. Electronic reporting of the hourly PM CPMS output shall begin with the later of the first operating hour on or after January 1, 2024; or the first operating hour after completion of the initial performance stack test that establishes the operating limit for the PM CPMS.

(5) If you elect to monitor SO<sub>2</sub> emission rate continuously as a surrogate for HCl, you must use the ECMPS Client Tool to submit the following information to EPA (except where it is already required to be reported or has been previously provided under the Acid Rain Program or another emissions reduction program that requires the use of part 75 of this chapter):

(i) Monitoring plan information for the SO<sub>2</sub> CEMS and for any additional monitoring systems that are required to convert SO<sub>2</sub> concentrations to units of the emission standard, in accordance with sections 75.62 and 75.64(a)(4) of this chapter;

(ii) Certification, recertification, quality-assurance, and diagnostic test results for the SO<sub>2</sub> CEMS and for any additional monitoring systems that are required to convert SO<sub>2</sub> concentrations to units of the emission standard, in accordance with section 75.64(a)(5); and

(iii) Quarterly electronic emissions reports. You must submit an electronic quarterly report within 30 days after the end of each calendar quarter, starting with a report for the calendar quarter in which the initial 30 boiler operating day performance test begins. Each report must include the following information:

(A) The applicable operating data specified in section 75.57(b) of this chapter;

(B) An hourly data stream for the unadjusted SO<sub>2</sub> concentration (in ppm, rounded to one decimal place), and separate unadjusted hourly data streams for the other parameters needed to convert the SO<sub>2</sub> concentrations to units of the standard. (*Note:* If a default moisture value is used in the emission rate calculations, an hourly data stream is not required for moisture; rather, the default value must be reported in the electronic monitoring plan.);

(C) An hourly SO<sub>2</sub> emission rate data stream, in units of the standard (*i.e.*, lb/MMBtu or lb/MWh, as applicable), calculated according to 40 CFR 63.10007(e) and (f)(1), rounded to the same precision as the emission standard (*i.e.*, with one leading non-zero digit and one decimal place), expressed in scientific notation. Use the following rounding convention: If the digit immediately following the first decimal place is 5 or greater, round the first decimal place upward (increase it by one); if the digit immediately following the first decimal place is 4 or less, leave the first decimal place unchanged;

(D) The results of all required daily quality-assurance tests of the SO<sub>2</sub> monitor and the additional monitors used to convert SO<sub>2</sub> concentration to units of the standard, as specified in appendix B to part 75 of this chapter; and

(E) A compliance certification, which includes a statement, based on reasonable inquiry of those persons with primary responsibility for ensuring that all SO<sub>2</sub> emissions from the affected EGUs under this subpart have been correctly and fully monitored, by a responsible official with that official's name, title, and signature, certifying that, to the best of his or her knowledge, the report is true, accurate, and complete. You must submit such a compliance certification statement in support of each quarterly report.

(b) You must submit semiannual compliance reports according to the requirements in paragraphs (b)(1) through (5) of this section.

(1) The first compliance report must cover the period beginning on the compliance date that is specified for your affected source in 40 CFR 63.9984 (or, if applicable, the extended compliance date approved under 40 CFR 63.6(i)(4)) and ending on June 30 or December 31, whichever date is the first date that occurs at least 180 days after the compliance date that is specified for your source in 40 CFR 63.9984 (or, if applicable, the extended compliance date approved under 40 CFR 63.6(i)(4)).



(2) The first compliance report must be submitted electronically no later than July 31 or January 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in 40 CFR 63.9984 (or, if applicable, the extended compliance date approved under 40 CFR 63.6(i)(4)).

(3) Each subsequent compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) Each subsequent compliance report must be submitted electronically no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(5) For each affected source that is subject to permitting regulations pursuant to part 70 or part 71 of this chapter, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), through the reporting period that ends December 31, 2023, you may submit the first and subsequent compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (4) of this section.

(6) The final semiannual compliance report shall cover the reporting period from July 1, 2023, through December 31, 2023. Quarterly compliance reports shall be submitted thereafter, in accordance with paragraph (g) of this section, starting with a report covering the first calendar quarter of 2024.

(c) The semiannual compliance report must contain the information required in paragraphs (c)(1) through (10) of this section.

(1) The information required by the summary report located in 63.10(e)(3)(vi).

(2) The total fuel use by each affected source subject to an emission limit, for each calendar month within the semiannual reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by EPA or your basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure.

(3) Indicate whether you burned new types of fuel during the reporting period. If you did burn new types of fuel you must include the date of the performance test where that fuel was in use.

(4) Include the date of the most recent tune-up for each EGU. The date of the tune-up is the date the tune-up provisions specified in § 63.10021(e)(6) and (7) were completed.

(5) Should you choose to rely on paragraph (2) of the definition of "startup" in § 63.10042 for your EGU, for each instance of startup or shutdown you shall:

(i) Include the maximum clean fuel storage capacity and the maximum hourly heat input that can be provided for each clean fuel determined according to the requirements of § 63.10032(f).

(ii) Include the information required to be monitored, collected, or recorded according to the requirements of § 63.10020(e).

(iii)—(v) [Reserved]

(6) You must report emergency bypass information annually from EGUs with LEE status.

(7) A summary of the results of the annual performance tests and documentation of any operating limits that were reestablished during the test, if applicable. If you are conducting stack tests once every 3 years to maintain LEE status, consistent with § 63.10006(b), the date of each stack test conducted during the previous 3 years, a comparison of emission level you achieved in each stack test conducted during the previous 3 years to the 50 percent emission limit threshold required in § 63.10005(h)(1)(i), and a statement as to whether there have been any operational changes since the last stack test that could increase emissions.

(8) A certification.

(9) If you have a deviation from any emission limit, work practice standard, or operating limit, you must also submit a brief description of the deviation, the duration of the deviation, emissions point identification, and the cause of the deviation.

(10) If you had any process or control equipment malfunction(s) during the reporting period, you must include the number, duration, and a brief description for each type of malfunction which occurred during the semiannual reporting period which caused or may have caused any applicable emission limitation to be exceeded.

(d) Excess emissions and deviation reporting. For EGUs whose owners or operators rely on a CMS to comply with an emissions or operating limit, the semiannual compliance reports described in paragraph (c) of this section must include the excess emissions and monitor downtime summary report described in 40 CFR 63.10(e)(3)(vi). However, starting with the first calendar quarter of 2024, reporting of the information under 40 CFR 63.10(e)(3)(vi) (and under paragraph (e)(3)(v), if the applicable excess emissions and/or monitor downtime threshold is exceeded) is discontinued for all CMS, and you must, instead, include in the quarterly compliance reports described in paragraph (g) of this section the applicable data elements in section 13 of appendix E to this subpart for any "deviation" (as defined in 40 CFR 63.10042 and elsewhere in this subpart) that occurred during the calendar quarter. If there were no deviations, you must include a statement to that effect in the quarterly compliance report.

(e) Each affected source that has obtained a title V operating permit pursuant to part 70 or part 71 of this chapter must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a semiannual compliance report pursuant to paragraphs (c) and (d) of this section, or two quarterly compliance reports covering the appropriate calendar half pursuant to paragraph (g) of this section, along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the compliance report(s) includes all required information concerning deviations from any emission limit, operating limit, or work practice requirement in this subpart, submission of the compliance report(s) satisfies any obligation to report the same deviations in the semiannual monitoring report. Submission of the compliance report(s) does not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.

(f) For each performance stack test completed prior to January 1, 2024, (including 30- (or 90-) boiler operating day Hg LEE demonstration tests and PM tests to establish operating limits for PM CPMS), you must submit a PDF test report in accordance with paragraph (f)(6) of this section, no later than 60 days after the date on which the testing is completed. For each test completed on or after January 1, 2024, in accordance with 40 CFR 63.10031(g), submit the applicable reference method information in sections 17 through 31 of appendix E to this subpart along with the quarterly compliance report for the calendar quarter in which the test was completed.

(1) For each RATA of an Hg, HCl, HF, or SO<sub>2</sub> monitoring system completed prior to January 1, 2024, and for each PM CEMS correlation test, each relative response audit (RRA) and each response correlation audit (RCA) of a PM CEMS completed prior to that date, you must submit a PDF test report in accordance with paragraph (f)(6) of this section, no later than 60 days after the date on which the test is completed. For each SO<sub>2</sub> or Hg RATA completed on or after January 1, 2024, you must submit the applicable reference method information in sections 17 through 31 of appendix E to this subpart prior to or concurrent with the relevant quarterly emissions report. For HCl or HF RATAs, and for correlation tests, RRAs, and RCAs of PM CEMS that are completed on or after January 1, 2024, submit the appendix E reference method information together with the summarized electronic test results, in accordance with section 11.4 of appendix B to this subpart or section 7.2.4 of appendix C to this part, as applicable.

(2) If, for a particular EGU or a group of EGUs serving a common stack, you have elected to demonstrate compliance using a PM CEMS, an approved HAP metals CEMS, or a PM CPMS, you must submit quarterly PDF reports in accordance with paragraph (f)(6) of this section, which include all of the 30-boiler operating day rolling average emission rates derived from the CEMS data or the 30-boiler operating day rolling average responses derived from the PM CPMS data (as applicable). The quarterly reports are due within 60 days after the reporting periods ending on March 31st, June 30th, September 30th, and December 31st. Submission of these quarterly reports in PDF files shall end with the report that covers the fourth calendar quarter of 2023. Beginning with the first calendar quarter of 2024, the compliance averages shall no longer be reported separately, but shall be incorporated into the quarterly compliance reports described in paragraph (g) of this section. In addition to the compliance averages for PM CEMS, PM CPMS, and/or HAP metals CEMS, the quarterly compliance reports described in paragraph (g) of this section must also include the 30- (or, if applicable 90-) boiler operating day

rolling average emission rates for Hg, HCl, HF, and/or SO<sub>2</sub>, if you have elected to (or are required to) continuously monitor these pollutants. Further, if your EGU or common stack is in an averaging plan, your quarterly compliance reports must identify all of the EGUs or common stacks in the plan and must include all of the 30- (or 90-) group boiler operating day rolling weighted average emission rates (WAERs) for the averaging group.

(3) [Reserved]

(4) You must submit semiannual compliance reports as required under paragraphs (b) through (d) of this section, ending with a report covering the semiannual period from July 1 through December 31, 2023, and Notifications of Compliance Status as required under section 63.10030(e), as PDF files. Quarterly compliance reports shall be submitted in XML format thereafter, in accordance with paragraph (g) of this section, starting with a report covering the first calendar quarter of 2024.

(5) All reports required by this subpart not subject to the requirements in paragraphs (f) introductory text and (f)(1) through (4) of this section must be sent to the Administrator at the appropriate address listed in § 63.13. If acceptable to both the Administrator and the owner or operator of an EGU, these reports may be submitted on electronic media. The Administrator retains the right to require submittal of reports subject to paragraphs (f) introductory text and (f)(1) through (4) of this section in paper format.

(6) All reports and notifications described in paragraphs (f) introductory text, (f)(1), (2), and (4) of this section shall be submitted to the EPA in the specified format and at the specified frequency, using the ECMPs Client Tool. Each PDF version of a stack test report, CEMS RATA report, PM CEMS correlation test report, RRA report, and RCA report must include sufficient information to assess compliance and to demonstrate that the reference method testing was done properly. Note that EPA will continue to accept, as necessary, PDF reports that are being phased out at the end of 2023, if the submission deadlines for those reports extend beyond December 31, 2023. The following data elements must be entered into the ECMPs Client Tool at the time of submission of each PDF file:

- (i) The facility name, physical address, mailing address (if different from the physical address), and county;
- (ii) The ORIS code (or equivalent ID number assigned by EPA's Clean Air Markets Division (CAMD)) and the Facility Registry System (FRS) ID;
- (iii) The EGU (or EGUs) to which the report applies. Report the EGU IDs as they appear in the CAMD Business System;
- (iv) If any of the EGUs in paragraph (f)(6)(iii) of this section share a common stack, indicate which EGUs share the stack. If emissions data are monitored and reported at the common stack according to part 75 of this chapter, report the ID number of the common stack as it is represented in the electronic monitoring plan required under § 75.53 of this chapter;
- (v) If any of the EGUs described in paragraph (f)(6)(iii) of this section are in an averaging plan under § 63.10009, indicate which EGUs are in the plan and whether it is a 30- or 90-day averaging plan;
- (vi) The identification of each emission point to which the report applies. An "emission point" is a point at which source effluent is released to the atmosphere, and is either a dedicated stack that serves one of the EGUs identified in paragraph (f)(6)(iii) of this section or a common stack that serves two or more of those EGUs. To identify an emission point, associate it with the EGU or stack ID in the CAMD Business system or the electronic monitoring plan (e.g., "Unit 2 stack," "common stack CS001," or "multiple stack MS001");
- (vii) An indication of the type of PDF report or notification being submitted;
- (viii) The pollutant(s) being addressed in the report;
- (ix) The reporting period being covered by the report (if applicable);

- (x) The relevant test method that was performed for a performance test (if applicable);
- (xi) The date the performance test was completed (if applicable) and the test number (if applicable); and
- (xii) The responsible official's name, title, and phone number.

(g) Starting with a report for the first calendar quarter of 2024, you must use the ECMPS Client Tool to submit quarterly electronic compliance reports. Each quarterly compliance report shall include the applicable data elements in sections 2 through 13 of appendix E to this subpart. For each stack test summarized in the compliance report, you must also submit the applicable reference method information in sections 17 through 31 of appendix E to this subpart. The compliance reports and associated appendix E information must be submitted no later than 60 days after the end of each calendar quarter.

(h) On and after January 1, 2024, initial Notifications of Compliance Status (if any) shall be submitted in accordance with 40 CFR 63.9(h)(2)(ii), as PDF files, using the ECMPS Client Tool. The applicable data elements in paragraphs (f)(6)(i) through (xii) of this section must be entered into ECMPS with each Notification.

(i) If you have elected to use paragraph (2) of the definition of "startup" in 40 CFR 63.10042, then, for startup and shutdown incidents that occur on or prior to December 31, 2023, you must include the information in 40 CFR 63.10031(c)(5) in the semiannual compliance report, in a PDF file. If you have elected to use paragraph (2) of the definition of "startup" in 40 CFR 63.10042, then, for startup and shutdown event(s) that occur on or after January 1, 2024, you must use the ECMPS Client Tool to submit the information in 40 CFR 63.10031(c)(5) and 40 CFR 63.10020(e) along with each quarterly compliance report, in a PDF file, starting with a report for the first calendar quarter of 2024. The applicable data elements in paragraphs (f)(6)(i) through (xii) of this section must be entered into ECMPS with each startup and shutdown report.

(j) If you elect to use a certified PM CEMS to monitor PM emissions continuously to demonstrate compliance with this subpart and have begun recording valid data from the PM CEMS prior to November 9, 2020, you must use the ECMPS Client Tool to submit a detailed report of your PS 11 correlation test (see appendix B to part 60 of this chapter) in a PDF file no later than 60 days after that date. For a correlation test completed on or after November 9, 2020, but prior to January 1, 2024, you must submit the PDF report no later than 60 days after the date on which the test is completed. For a correlation test completed on or after January 1, 2024, you must submit the PDF report according to section 7.2.4 of appendix C to this subpart. The applicable data elements in paragraph (f)(6)(i) through (xii) of this section must be entered into ECMPS with the PDF report.

(k) If you elect to demonstrate compliance using a PM CPMS or an approved HAP metals CEMS, you must submit quarterly reports of your QA/QC activities (e.g., calibration checks, performance audits), in a PDF file, beginning with a report for the first quarter of 2024, if the PM CPMS or HAP metals CEMS is used for the compliance demonstration in that quarter. Otherwise, submit a report for the first calendar quarter in which the PM CPMS or HAP metals CEMS is used to demonstrate compliance. These reports are due no later than 60 days after the end of each calendar quarter. The applicable data elements in paragraph (f)(6)(i) through (xii) of this section must be entered into ECMPS with the PDF report.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23404, Apr. 19, 2012; 79 FR 68791, Nov. 19, 2014; 79 FR 68799, Nov. 19, 2014; 80 FR 15514, Mar. 24, 2015; 81 FR 20188, Apr. 6, 2016; 82 FR 16739, Apr. 6, 2017; 83 FR 30883, July 2, 2018; 85 FR 55760, Sept. 9, 2020]

### **§ 63.10032 What records must I keep?**

(a) You must keep records according to paragraphs (a)(1) and (2) of this section. If you are required to (or elect to) continuously monitor Hg and/or HCl and/or HF and/or PM emissions, or if you elect to use a PM CPMS, you must keep the records required under appendix A and/or appendix B and/or appendix C and/or appendix D to this subpart. If you elect to conduct periodic (e.g., quarterly or annual) performance stack tests, then, for each test completed on or after January 1, 2024, you must keep records of the applicable data elements under 40 CFR 63.7(g). You must also keep records of all data elements and other information in appendix E to this subpart that apply to your compliance strategy.

(1) In accordance with 40 CFR 63.10(b)(2)(xiv), a copy of each notification or report that you submit to comply with this subpart. You must also keep records of all supporting documentation for the initial Notifications of Compliance Status, semiannual compliance reports, or quarterly compliance reports that you submit.

(2) Records of performance stack tests, fuel analyses, or other compliance demonstrations and performance evaluations, as required in § 63.10(b)(2)(viii).

(b) For each CEMS and CPMS, you must keep records according to paragraphs (b)(1) through (4) of this section.

(1) Records described in § 63.10(b)(2)(vi) through (xi).

(2) Previous (*i.e.*, superseded) versions of the performance evaluation plan as required in § 63.8(d)(3).

(3) Request for alternatives to relative accuracy test for CEMS as required in § 63.8(f)(6)(i).

(4) Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period.

(c) You must keep the records required in Table 7 to this subpart including records of all monitoring data and calculated averages for applicable PM CPMS operating limits to show continuous compliance with each emission limit and operating limit that applies to you.

(d) For each EGU subject to an emission limit, you must also keep the records in paragraphs (d)(1) through (3) of this section.

(1) You must keep records of monthly fuel use by each EGU, including the type(s) of fuel and amount(s) used.

(2) If you combust non-hazardous secondary materials that have been determined not to be solid waste pursuant to 40 CFR 241.3(b)(1), you must keep a record which documents how the secondary material meets each of the legitimacy criteria. If you combust a fuel that has been processed from a discarded non-hazardous secondary material pursuant to 40 CFR 241.3(b)(2), you must keep records as to how the operations that produced the fuel satisfies the definition of processing in 40 CFR 241.2. If the fuel received a non-waste determination pursuant to the petition process submitted under 40 CFR 241.3(c), you must keep a record which documents how the fuel satisfies the requirements of the petition process.

(3) For an EGU that qualifies as an LEE under § 63.10005(h), you must keep annual records that document that your emissions in the previous stack test(s) continue to qualify the unit for LEE status for an applicable pollutant, and document that there was no change in source operations including fuel composition and operation of air pollution control equipment that would cause emissions of the pollutant to increase within the past year.

(e) If you elect to average emissions consistent with § 63.10009, you must additionally keep a copy of the emissions averaging implementation plan required in § 63.10009(g), all calculations required under § 63.10009, including daily records of heat input or steam generation, as applicable, and monitoring records consistent with § 63.10022.

(f) Regarding startup periods or shutdown periods:

(1) Should you choose to rely on paragraph (1) of the definition of "startup" in § 63.10042 for your EGU, you must keep records of the occurrence and duration of each startup or shutdown.

(2) Should you choose to rely on paragraph (2) of the definition of "startup" in § 63.10042 for your EGU, you must keep records of:

(i) The determination of the maximum possible clean fuel capacity for each EGU;

(ii) The determination of the maximum possible hourly clean fuel heat input and of the hourly clean fuel heat input for each EGU; and

(iii) The information required in § 63.10020(e).

(g) You must keep records of the occurrence and duration of each malfunction of an operation (*i.e.*, process equipment) or the air pollution control and monitoring equipment.

(h) You must keep records of actions taken during periods of malfunction to minimize emissions in accordance with § 63.10000(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(i) You must keep records of the type(s) and amount(s) of fuel used during each startup or shutdown.

(j) If you elect to establish that an EGU qualifies as a limited-use liquid oil-fired EGU, you must keep records of the type(s) and amount(s) of fuel use in each calendar quarter to document that the capacity factor limitation for that subcategory is met.

[77 FR 9464, Feb. 16, 2012, as amended at 79 FR 68792, Nov. 19, 2014; 81 FR 20189, Apr. 6, 2016; 85 FR 55763, Sept. 9, 2020]

#### **§ 63.10033 In what form and how long must I keep my records?**

(a) Your records must be in a form suitable and readily available for expeditious review, according to § 63.10(b)(1).

(b) As specified in § 63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 63.10(b)(1). You can keep the records off site for the remaining 3 years.

#### **Other Requirements and Information**

#### **§ 63.10040 What parts of the General Provisions apply to me?**

Table 9 to this subpart shows which parts of the General Provisions in §§ 63.1 through 63.15 apply to you.

#### **§ 63.10041 Who implements and enforces this subpart?**

(a) This subpart can be implemented and enforced by U.S. EPA, or a delegated authority such as your state, local, or tribal agency. If the EPA Administrator has delegated authority to your state, local, or tribal agency, then that agency (as well as the U.S. EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if this subpart is delegated to your state, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a state, local, or tribal agency under 40 CFR part 63, subpart E, the authorities listed in paragraphs (b)(1) through (4) of this section are retained by the EPA Administrator and are not transferred to the state, local, or tribal agency; moreover, the U.S. EPA retains oversight of this subpart and can take enforcement actions, as appropriate, with respect to any failure by any person to comply with any provision of this subpart.

(1) Approval of alternatives to the non-opacity emission limits and work practice standards in § 63.9991(a) and (b) under § 63.6(g).

(2) Approval of major change to test methods in Table 5 to this subpart under § 63.7(e)(2)(ii) and (f) and as defined in § 63.90, approval of minor and intermediate changes to monitoring performance

specifications/procedures in Table 5 where the monitoring serves as the performance test method (see definition of “test method” in § 63.2).

(3) Approval of major changes to monitoring under § 63.8(f) and as defined in § 63.90.

(4) Approval of major change to recordkeeping and reporting under § 63.10(e) and as defined in § 63.90.

### **§ 63.10042 What definitions apply to this subpart?**

Terms used in this subpart are defined in the Clean Air Act (CAA), in § 63.2 (the General Provisions), and in this section as follows:

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

*Anthracite coal* means solid fossil fuel classified as anthracite coal by American Society of Testing and Materials (ASTM) Method D388–05, “Standard Classification of Coals by Rank” (incorporated by reference, see § 63.14).

*Bituminous coal* means coal that is classified as bituminous according to ASTM Method D388–05, “Standard Classification of Coals by Rank” (incorporated by reference, see § 63.14).

*Boiler operating day* means a 24-hour period that begins at midnight and ends the following midnight during which any fuel is combusted at any time in the EGU, excluding startup periods or shutdown periods. It is not necessary for the fuel to be combusted the entire 24-hour period.

*Capacity factor* for a liquid oil-fired EGU means the total annual heat input from oil divided by the product of maximum hourly heat input for the EGU, regardless of fuel, multiplied by 8,760 hours.

*Clean fuel* means natural gas, synthetic natural gas that meets the specification necessary for that gas to be transported on a Federal Energy Regulatory Commission (FERC) regulated pipeline, propane, distillate oil, synthesis gas that has been processed through a gas clean-up train such that it could be used in a system's combustion turbine, or ultra-low-sulfur diesel (ULSD) oil, including those fuels meeting the requirements of 40 CFR part 80, subpart I (“Subpart I—Motor Vehicle Diesel Fuel; Nonroad, Locomotive, and Marine Diesel Fuel; and ECA Marine Fuel”).

*Coal* means all solid fuels classifiable as anthracite, bituminous, sub-bituminous, or lignite by ASTM Method D388–05, “Standard Classification of Coals by Rank” (incorporated by reference, see § 63.14), and coal refuse. Synthetic fuels derived from coal for the purpose of creating useful heat including but not limited to, coal derived gases (not meeting the definition of natural gas), solvent-refined coal, coal-oil mixtures, and coal-water mixtures, are considered “coal” for the purposes of this subpart.

*Coal-fired electric utility steam generating unit* means an electric utility steam generating unit meeting the definition of “fossil fuel-fired” that burns coal for more than 10.0 percent of the average annual heat input during the 3 previous calendar years after the compliance date for your facility in § 63.9984 or for more than 15.0 percent of the annual heat input during any one of those calendar years. EGU owners and operators must estimate coal, oil, and natural gas usage for the first 3 calendar years after the applicable compliance date and they are solely responsible for assuring compliance with this final rule or other applicable standard based on their fuel usage projections. After the first 3 years of compliance, EGUs are required to evaluate applicability based on coal or oil usage from the three previous calendar years on an annual rolling basis.

*Coal refuse* means waste products of coal mining, physical coal cleaning, and coal preparation operations (e.g. culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material.

*Cogeneration* means a steam-generating unit that simultaneously produces both electrical and useful thermal (or mechanical) energy from the same primary energy source.

*Cogeneration unit* means a stationary, fossil fuel-fired EGU meeting the definition of “fossil fuel-fired” or stationary, integrated gasification combined cycle:

- (1) Having equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy; and
- (2) Producing during the 12-month period starting on the date the unit first produces electricity and during any calendar year after which the unit first produces electricity:
  - (i) For a topping-cycle cogeneration unit,
    - (A) Useful thermal energy not less than 5 percent of total energy output; and
    - (B) Useful power that, when added to one-half of useful thermal energy produced, is not less than 42.5 percent of total energy input, if useful thermal energy produced is 15 percent or more of total energy output, or not less than 45 percent of total energy input, if useful thermal energy produced is less than 15 percent of total energy output.
  - (ii) For a bottoming-cycle cogeneration unit, useful power not less than 45 percent of total energy input.
- (3) Provided that the total energy input under paragraphs (2)(i)(B) and (2)(ii) of this definition shall equal the unit's total energy input from all fuel except biomass if the unit is a boiler.

*Combined-cycle gas stationary combustion turbine* means a stationary combustion turbine system where heat from the turbine exhaust gases is recovered by a waste heat boiler.

*Common stack* means the exhaust of emissions from two or more affected units through a single flue.

*Continental liquid oil-fired subcategory* means any oil-fired electric utility steam generating unit that burns liquid oil and is located in the continental United States.

*Default electrical load* means an electrical load equal to 5 percent of the maximum sustainable electrical output (megawatts), as defined in section 6.5.2.1(a)(1) of Appendix A to part 75 of this chapter, of an affected EGU that is in startup or shutdown mode. For monitored common stack configurations, the default electrical load is 5 percent of the combined maximum sustainable electrical load of the EGUs that are in startup or shutdown mode during an hour in which the electrical load for all operating EGUs is zero. The default electrical load is used to calculate the electrical output-based emission rate (lb/MWh or lb/GWh, as applicable) for any startup or shutdown hour in which the actual electrical load is zero. The default electrical load is not used for EGUs required to make heat input-based emission rate (lb/MMBtu or lb/TBtu, as applicable) calculations. For the purposes of this subpart, the default electrical load is not considered to be a substitute data value.

*Deviation.*

- (1) **Deviation** means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:
  - (i) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, work practice standard, or monitoring requirement; or
  - (ii) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit.
- (2) A deviation is not always a violation. The determination of whether a deviation constitutes a violation of the standard is up to the discretion of the entity responsible for enforcement of the standards.



*Diluent cap* means a default CO<sub>2</sub> or O<sub>2</sub> concentration that may be used to calculate the Hg, HCl, HF, PM, or SO<sub>2</sub> emission rate (lb/MMBtu or lb/TBtu, as applicable) during a startup or shutdown hour in which the measured CO<sub>2</sub> concentration is below the cap value or the measured O<sub>2</sub> concentration is above the cap value. The appropriate diluent cap values for EGUs are presented in § 63.10007(f) and in section 6.2.1.2 of Appendix A to this subpart. For the purposes of this subpart, the diluent cap is not considered to be a substitute data value.

*Distillate oil* means fuel oils, including recycled oils, that comply with the specifications for fuel oil numbers 1 and 2, as defined by ASTM Method D396–10, “Standard Specification for Fuel Oils” (incorporated by reference, see § 63.14).

*Dry flue gas desulfurization technology, or dry FGD, or spray dryer absorber (SDA), or spray dryer, or dry scrubber* means an add-on air pollution control system located downstream of the steam generating unit that injects a dry alkaline sorbent (dry sorbent injection) or sprays an alkaline sorbent slurry (spray dryer) to react with and neutralize acid gases such as SO<sub>2</sub> and HCl in the exhaust stream forming a dry powder material. Alkaline sorbent injection systems in fluidized bed combustors (FBC) or circulating fluidized bed (CFB) boilers are included in this definition.

*Dry sorbent injection (DSI)* means an add-on air pollution control system in which sorbent (e.g., conventional activated carbon, brominated activated carbon, Trona, hydrated lime, sodium carbonate, etc.) is injected into the flue gas stream upstream of a PM control device to react with and neutralize acid gases (such as SO<sub>2</sub> and HCl) or Hg in the exhaust stream forming a dry powder material that may be removed in a primary or secondary PM control device.

*Eastern bituminous coal refuse (EBCR)* means coal refuse generated from the mining of bituminous coal in Pennsylvania and West Virginia.

*Electric Steam generating unit* means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with integrated gasification combined cycle gas turbines; nuclear steam generators are not included) for the purpose of powering a generator to produce electricity or electricity and other thermal energy.

*Electric utility steam generating unit (EGU)* means a fossil fuel-fired combustion unit of more than 25 megawatts electric (MWe) that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is considered an electric utility steam generating unit.

*Emission limitation* means any emissions limit, work practice standard, or operating limit.

*Excess emissions* means, with respect to this subpart, results of any required measurements outside the applicable range (e.g., emissions limitations, parametric operating limits) that is permitted by this subpart. The values of measurements will be in the same units and averaging time as the values specified in this subpart for the limitations.

*Federally enforceable* means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60, 61, and 63; requirements within any applicable state implementation plan; and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 40 CFR 51.24.

*Flue gas desulfurization system* means any add-on air pollution control system located downstream of the steam generating unit whose purpose or effect is to remove at least 50 percent of the SO<sub>2</sub> in the exhaust gas stream.

*Fossil fuel* means natural gas, oil, coal, and any form of solid, liquid, or gaseous fuel derived from such material.

*Fossil fuel-fired* means an electric utility steam generating unit (EGU) that is capable of producing more than 25 MW of electrical output from the combustion of fossil fuels. To be “capable of combusting” fossil fuels, an EGU would need to have these fuels allowed in its operating permit and have the appropriate fuel handling facilities on-site or otherwise available (e.g., coal handling equipment, including coal storage area, belts and conveyers, pulverizers, etc.; oil storage facilities). In addition, fossil fuel-fired means any EGU that fired fossil fuels for more than 10.0 percent of the average annual heat input during the 3 previous calendar years after the compliance date for your facility in § 63.9984 or for more than 15.0 percent of the annual heat input during any one of those

calendar years. EGU owners and operators must estimate coal, oil, and natural gas usage for the first 3 calendar years after the applicable compliance date and they are solely responsible for assuring compliance with this final rule or other applicable standard based on their fuel usage projections. After the first 3 years of compliance, EGUs are required to evaluate applicability based on coal or oil usage from the three previous calendar years on an annual rolling basis.

*Fuel type* means each category of fuels that share a common name or classification. Examples include, but are not limited to, bituminous coal, subbituminous coal, lignite, anthracite, biomass, and residual oil. Individual fuel types received from different suppliers are not considered new fuel types.

*Fluidized bed boiler, or fluidized bed combustor, or circulating fluidized boiler, or CFB* means a boiler utilizing a fluidized bed combustion process.

*Fluidized bed combustion* means a process where a fuel is burned in a bed of granulated particles which are maintained in a mobile suspension by the upward flow of air and combustion products.

*Gaseous fuel* includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, solid oil-derived gas, refinery gas, and biogas.

*Generator* means a device that produces electricity.

*Gross output* means the gross useful work performed by the steam generated and, for an IGCC electric utility steam generating unit, the work performed by the stationary combustion turbines. For a unit generating only electricity, the gross useful work performed is the gross electrical output from the unit's turbine/generator sets. For a cogeneration unit, the gross useful work performed is the gross electrical output, including any such electricity used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls), or mechanical output plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (*i.e.*, steam delivered to an industrial process).

*Heat input* means heat derived from combustion of fuel in an EGU (synthetic gas for an IGCC) and does not include the heat input from preheated combustion air, recirculated flue gases, or exhaust gases from other sources such as gas turbines, internal combustion engines, etc.

*Integrated gasification combined cycle electric utility steam generating unit or IGCC* means an electric utility steam generating unit meeting the definition of "fossil fuel-fired" that burns a synthetic gas derived from coal and/or solid oil-derived fuel for more than 10.0 percent of the average annual heat input during the 3 previous calendar years after the compliance date for your facility in § 63.9984 or for more than 15.0 percent of the annual heat input during any one of those calendar years in a combined-cycle gas turbine. EGU owners and operators must estimate coal, oil, and natural gas usage for the first 3 calendar years after the applicable compliance date and they are solely responsible for assuring compliance with this final rule or other applicable standard based on their fuel usage projections. No solid coal or solid oil-derived fuel is directly burned in the unit during operation. After the first 3 years of compliance, EGUs are required to evaluate applicability based on coal or oil usage from the three previous calendar years on an annual rolling basis.

*ISO conditions* means a temperature of 288 Kelvin, a relative humidity of 60 percent, and a pressure of 101.3 kilopascals.

*Lignite coal* means coal that is classified as lignite A or B according to ASTM Method D388-05, "Standard Classification of Coals by Rank" (incorporated by reference, see § 63.14).

*Limited-use liquid oil-fired subcategory* means an oil-fired electric utility steam generating unit with an annual capacity factor when burning oil of less than 8 percent of its maximum or nameplate heat input, whichever is greater, averaged over a 24-month block contiguous period commencing on the first of the month following the compliance date specified in § 63.9984.

*Liquid fuel* includes, but is not limited to, distillate oil and residual oil.

*Monitoring system malfunction* means any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions.

*Natural gas* means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1,100 Btu per standard cubic foot. Natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

*Natural gas-fired electric utility steam generating unit* means an electric utility steam generating unit meeting the definition of "fossil fuel-fired" that is not a coal-fired, oil-fired, or IGCC electric utility steam generating unit and that burns natural gas for more than 10.0 percent of the average annual heat input during the 3 previous calendar years after the compliance date for your facility in § 63.9984 or for more than 15.0 percent of the annual heat input during any one of those calendar years. EGU owners and operators must estimate coal, oil, and natural gas usage for the first 3 calendar years after the applicable compliance date and they are solely responsible for assuring compliance with this final rule or other applicable standard based on their fuel usage projections.

*Net-electric output* means the gross electric sales to the utility power distribution system minus purchased power on a calendar year basis.

*Net summer capacity* means the maximum output, commonly expressed in megawatts (MW), that generating equipment can supply to system load, as demonstrated by a multi-hour test, at the time of summer peak demand (period of June 1 through September 30.) This output reflects a reduction in capacity due to electricity use for station service or auxiliaries.

*Neural network* or *neural net* for purposes of this rule means an automated boiler optimization system. A neural network typically has the ability to process data from many inputs to develop, remember, update, and enable algorithms for efficient boiler operation.

*Non-continental area* means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

*Non-continental liquid oil-fired subcategory* means any oil-fired electric utility steam generating unit that burns liquid oil and is located outside the continental United States.

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

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

*Oil-fired electric utility steam generating unit* means an electric utility steam generating unit meeting the definition of "fossil fuel-fired" that is not a coal-fired electric utility steam generating unit and that burns oil for more than 10.0 percent of the average annual heat input during the 3 previous calendar years after the compliance date for your facility in § 63.9984 or for more than 15.0 percent of the annual heat input during any one of those calendar years. EGU owners and operators must estimate coal, oil, and natural gas usage for the first 3 calendar years after the applicable compliance date and they are solely responsible for assuring compliance with this final rule or other applicable standard based on their fuel usage projections. After the first 3 years of compliance, EGUs are required to evaluate applicability based on coal or oil usage from the three previous calendar years on an annual rolling basis.

*Out-of-control period*, as it pertains to continuous monitoring systems, means any period:

- (1) Beginning with the hour corresponding to the completion of a daily calibration or quality assurance audit that indicates that the instrument fails to meet the applicable acceptance criteria; and
- (2) Ending with the hour corresponding to the completion of an additional calibration or quality assurance audit following corrective action showing that the instrument meets the applicable acceptance criteria.

*Particulate matter* or *PM* means any finely divided solid material as measured by the test methods specified under this subpart, or an alternative method.

*Pulverized coal (PC) boiler* means an EGU in which pulverized coal is introduced into an air stream that carries the coal to the combustion chamber of the EGU where it is fired in suspension.

*Residual oil* means crude oil, and all fuel oil numbers 4, 5 and 6, as defined by ASTM Method D396–10, “Standard Specification for Fuel Oils” (incorporated by reference, see § 63.14).

*Responsible official* means responsible official as defined in 40 CFR 70.2.

*Shutdown* means the period in which cessation of operation of an EGU is initiated for any purpose. Shutdown begins when the EGU no longer generates electricity or makes useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes or when no coal, liquid oil, syngas, or solid oil-derived fuel is being fired in the EGU, whichever is earlier. Shutdown ends when the EGU no longer generates electricity or makes useful thermal energy (such as steam or heat) for industrial, commercial, heating, or cooling purposes, and no fuel is being fired in the EGU. Any fraction of an hour in which shutdown occurs constitutes a full hour of shutdown.

*Startup* means:

- (1) Either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on-site use). Any fraction of an hour in which startup occurs constitutes a full hour of startup; or
- (2) The period in which operation of an EGU is initiated for any purpose. Startup begins with either the firing of any fuel in an EGU for the purpose of producing electricity or useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes (other than the first-ever firing of fuel in a boiler following construction of the boiler) or for any other purpose after a shutdown event. Startup ends 4 hours after the EGU generates electricity that is sold or used for any other purpose (including on site use), or 4 hours after the EGU makes useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes (16 U.S.C. 796(18)(A) and 18 CFR 292.202(c)), whichever is earlier. Any fraction of an hour in which startup occurs constitutes a full hour of startup.

*Stationary combustion turbine* means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, the combustion turbine portion of any stationary cogeneration cycle combustion system, or the combustion turbine portion of any stationary combined cycle steam/electric generating system. Stationary means that the combustion turbine is not self propelled or intended to be propelled while performing its function. Stationary combustion turbines do not include turbines located at a research or laboratory facility, if research is conducted on the turbine itself and the turbine is not being used to power other applications at the research or laboratory facility.

*Steam generating unit* means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with integrated gasification combined cycle gas turbines; nuclear steam generators are not included).

*Stoker* means a unit consisting of a mechanically operated fuel feeding mechanism, a stationary or moving grate to support the burning of fuel and admit undergrate air to the fuel, an overfire air system to complete combustion, and an ash discharge system. There are two general types of stokers: underfeed and overfeed. Overfeed stokers include mass feed and spreader stokers.

*Subbituminous coal* means coal that is classified as subbituminous A, B, or C according to ASTM Method D388–05, “Standard Classification of Coals by Rank” (incorporated by reference, see § 63.14).

*Unit designed for coal  $\geq 8,300$  Btu/lb subcategory* means any coal-fired EGU that is not a coal-fired EGU in the “unit designed for low rank virgin coal” subcategory.

*Unit designed for eastern bituminous coal refuse (EBCR) subcategory* means any existing (*i.e.*, construction was commenced on or before May 3, 2011) coal-fired EGU with a net summer capacity of no greater than 150 MW that is designed to burn and that is burning 75 percent or more (by heat input) eastern bituminous coal refuse on a 12-month rolling average basis.

*Unit designed for low rank virgin coal subcategory* means any coal-fired EGU that is designed to burn and that is burning nonagglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of less than 19,305 kJ/kg (8,300 Btu/lb) that is constructed and operates at or near the mine that produces such coal.

*Unit designed to burn solid oil-derived fuel subcategory* means any oil-fired EGU that burns solid oil-derived fuel.

*Voluntary consensus standards or VCS* mean technical standards (e.g., materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. The EPA/OAQPS has by precedent only used VCS that are written in English. Examples of VCS bodies are: American Society of Testing and Materials (ASTM), American Society of Mechanical Engineers (ASME), International Standards Organization (ISO), Standards Australia (AS), British Standards (BS), Canadian Standards (CSA), European Standard (EN or CEN) and German Engineering Standards (VDI). The types of standards that are not considered VCS are standards developed by: the U.S. states, e.g., California (CARB) and Texas (TCEQ); industry groups, such as American Petroleum Institute (API), Gas Processors Association (GPA), and Gas Research Institute (GRI); and other branches of the U.S. government, e.g., Department of Defense (DOD) and Department of Transportation (DOT). This does not preclude EPA from using standards developed by groups that are not VCS bodies within an EPA rule. When this occurs, EPA has done searches and reviews for VCS equivalent to these non-VCS methods.

*Wet flue gas desulfurization technology, or wet FGD, or wet scrubber* means any add-on air pollution control device that is located downstream of the steam generating unit that mixes an aqueous stream or slurry with the exhaust gases from an EGU to control emissions of PM and/or to absorb and neutralize acid gases, such as SO<sub>2</sub> and HCl.

*Work practice standard* means any design, equipment, work practice, or operational standard, or combination thereof, which is promulgated pursuant to CAA section 112(h).

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23405, Apr. 19, 2012; 78 FR 24087, Apr. 24, 2013; 79 FR 68792, Nov. 19, 2014; 81 FR 20189, Apr. 6, 2016; 85 FR 20850, Apr. 15, 2020; 85 FR 55763, Sept. 9, 2020]

**Table 1 to Subpart UUUUU of Part 63—Emission Limits for New or Reconstructed EGUs**

As stated in § 63.9991, you must comply with the following applicable emission limits:

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
1. Coal-fired unit not low rank virgin coal	a. Filterable particulate matter (PM)	9.0E-2 lb/MWh <sup>1</sup>	Collect a minimum of 4 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	6.0E-2 lb/GWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E-3 lb/GWh	
	Arsenic (As)	3.0E-3 lb/GWh	
	Beryllium (Be)	6.0E-4 lb/GWh	
	Cadmium (Cd)	4.0E-4 lb/GWh	
	Chromium (Cr)	7.0E-3 lb/GWh	
	Cobalt (Co)	2.0E-3 lb/GWh	
	Lead (Pb)	2.0E-2 lb/GWh	
	Manganese (Mn)	4.0E-3 lb/GWh	
	Nickel (Ni)	4.0E-2 lb/GWh	
	Selenium (Se)	5.0E-2 lb/GWh	
	b. Hydrogen chloride (HCl)	1.0E-2 lb/MWh	For Method 26A at appendix A-8 to part 60 of this chapter, collect a minimum of 3 dscm per run. For ASTM D6348-03 <sup>2</sup> or Method 320 at appendix A to part 63 of this chapter, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO <sub>2</sub> ) <sup>3</sup>	1.0 lb/MWh	SO <sub>2</sub> CEMS.
	c. Mercury (Hg)	3.0E-3 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
2. Coal-fired units low rank virgin coal	a. Filterable particulate matter (PM)	9.0E-2 lb/MWh <sup>1</sup>	Collect a minimum of 4 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	6.0E-2 lb/GWh	Collect a minimum of 4 dscm per run.

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E-3 lb/GWh	
	Arsenic (As)	3.0E-3 lb/GWh	
	Beryllium (Be)	6.0E-4 lb/GWh	
	Cadmium (Cd)	4.0E-4 lb/GWh	
	Chromium (Cr)	7.0E-3 lb/GWh	
	Cobalt (Co)	2.0E-3 lb/GWh	
	Lead (Pb)	2.0E-2 lb/GWh	
	Manganese (Mn)	4.0E-3 lb/GWh	
	Nickel (Ni)	4.0E-2 lb/GWh	
	Selenium (Se)	5.0E-2 lb/GWh	
	b. Hydrogen chloride (HCl)	1.0E-2 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run For ASTM D6348–03 <sup>2</sup> or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO <sub>2</sub> ) <sup>3</sup>	1.0 lb/MWh	SO <sub>2</sub> CEMS.
	c. Mercury (Hg)	4.0E-2 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
3. IGCC unit	a. Filterable particulate matter (PM)	7.0E-2 lb/MWh <sup>4</sup> 9.0E-2 lb/MWh <sup>5</sup>	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	4.0E-1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	2.0E-2 lb/GWh	
	Arsenic (As)	2.0E-2 lb/GWh	
	Beryllium (Be)	1.0E-3 lb/GWh	
	Cadmium (Cd)	2.0E-3 lb/GWh	
	Chromium (Cr)	4.0E-2 lb/GWh	
	Cobalt (Co)	4.0E-3 lb/GWh	
	Lead (Pb)	9.0E-3 lb/GWh	

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	Manganese (Mn)	2.0E-2 lb/GWh	
	Nickel (Ni)	7.0E-2 lb/GWh	
	Selenium (Se)	3.0E-1 lb/GWh	
	b. Hydrogen chloride (HCl)	2.0E-3 lb/MWh	For Method 26A, collect a minimum of 1 dscm per run; for Method 26 at appendix A-8 to part 60 of this chapter, collect a minimum of 120 liters per run. For ASTM D6348-03 <sup>2</sup> or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO <sub>2</sub> ) <sup>3</sup>	4.0E-1 lb/MWh	SO <sub>2</sub> CEMS.
	c. Mercury (Hg)	3.0E-3 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
4. Liquid oil-fired unit—continental (excluding limited-use liquid oil-fired subcategory units)	a. Filterable particulate matter (PM)	3.0E-1 lb/MWh <sup>1</sup>	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	2.0E-4 lb/MWh	Collect a minimum of 2 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	1.0E-2 lb/GWh	
	Arsenic (As)	3.0E-3 lb/GWh	
	Beryllium (Be)	5.0E-4 lb/GWh	
	Cadmium (Cd)	2.0E-4 lb/GWh	
	Chromium (Cr)	2.0E-2 lb/GWh	
	Cobalt (Co)	3.0E-2 lb/GWh	
	Lead (Pb)	8.0E-3 lb/GWh	
	Manganese (Mn)	2.0E-2 lb/GWh	
	Nickel (Ni)	9.0E-2 lb/GWh	
	Selenium (Se)	2.0E-2 lb/GWh	
	Mercury (Hg)	1.0E-4 lb/GWh	For Method 30B at appendix A-8 to part 60 of this chapter sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be < 1/2 the standard.



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

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	Total non-Hg HAP metals	6.0E-1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E-3 lb/GWh	
	Arsenic (As)	3.0E-3 lb/GWh	
	Beryllium (Be)	6.0E-4 lb/GWh	
	Cadmium (Cd)	7.0E-4 lb/GWh	
	Chromium (Cr)	6.0E-3 lb/GWh	
	Cobalt (Co)	2.0E-3 lb/GWh	
	Lead (Pb)	2.0E-2 lb/GWh	
	Manganese (Mn)	7.0E-3 lb/GWh	
	Nickel (Ni)	4.0E-2 lb/GWh	
	Selenium (Se)	6.0E-3 lb/GWh	
	b. Hydrogen chloride (HCl)	4.0E-4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348-03 <sup>2</sup> or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO <sub>2</sub> ) <sup>3</sup>	1.0 lb/MWh	SO <sub>2</sub> CEMS.
	c. Mercury (Hg)	2.0E-3 lb/GWh	Hg CEMS or Sorbent trap monitoring system only.

<sup>1</sup> Gross output.

<sup>2</sup> Incorporated by reference, see § 63.14.

<sup>3</sup> You may not use the alternate SO<sub>2</sub> limit if your EGU does not have some form of FGD system (or, in the case of IGCC EGUs, some other acid gas removal system either upstream or downstream of the combined cycle block) and SO<sub>2</sub> CEMS installed.

<sup>4</sup> Duct burners on syngas; gross output.

<sup>5</sup> Duct burners on natural gas; gross output.

**Table 2 to Subpart UUUUU of Part 63—Emission Limits for Existing EGUs**

As stated in § 63.9991, you must comply with the following applicable emission limits:<sup>1</sup>

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
1. Coal-fired unit not low rank virgin coal	a. Filterable particulate matter (PM)	3.0E–2 lb/MMBtu or 3.0E–1 lb/MWh <sup>2</sup>	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	5.0E–5 lb/MMBtu or 5.0E–1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–1 lb/TBtu or 8.0E–3 lb/GWh	
	Arsenic (As)	1.1E0 lb/TBtu or 2.0E–2 lb/GWh	
	Beryllium (Be)	2.0E–1 lb/TBtu or 2.0E–3 lb/GWh	
	Cadmium (Cd)	3.0E–1 lb/TBtu or 3.0E–3 lb/GWh	
	Chromium (Cr)	2.8E0 lb/TBtu or 3.0E–2 lb/GWh	
	Cobalt (Co)	8.0E–1 lb/TBtu or 8.0E–3 lb/GWh	
	Lead (Pb)	1.2E0 lb/TBtu or 2.0E–2 lb/GWh	
	Manganese (Mn)	4.0E0 lb/TBtu or 5.0E–2 lb/GWh	
	Nickel (Ni)	3.5E0 lb/TBtu or 4.0E–2 lb/GWh	
	Selenium (Se)	5.0E0 lb/TBtu or 6.0E–2 lb/GWh	
	b. Hydrogen chloride (HCl)	2.0E–3 lb/MMBtu or 2.0E–2 lb/MWh	For Method 26A at appendix A–8 to part 60 of this chapter, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 <sup>3</sup> or Method 320 at appendix A to part 63 of this chapter, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO <sub>2</sub> ) <sup>4</sup>	2.0E–1 lb/MMBtu or 1.5E0 lb/MWh	SO <sub>2</sub> CEMS.

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	c. Mercury (Hg)	1.2E0 lb/TBtu or 1.3E-2 lb/GWh	LEE Testing for 30 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B at appendix A-8 to part 60 of this chapter run or Hg CEMS or sorbent trap monitoring system only.
		OR	
		1.0E0 lb/TBtu or 1.1E-2 lb/GWh	LEE Testing for 90 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
2. Coal-fired unit low rank virgin coal	a. Filterable particulate matter (PM)	3.0E-2 lb/MMBtu or 3.0E-1 lb/MWh <sup>2</sup>	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	5.0E-5 lb/MMBtu or 5.0E-1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E-1 lb/TBtu or 8.0E-3 lb/GWh	
	Arsenic (As)	1.1E0 lb/TBtu or 2.0E-2 lb/GWh	
	Beryllium (Be)	2.0E-1 lb/TBtu or 2.0E-3 lb/GWh	
	Cadmium (Cd)	3.0E-1 lb/TBtu or 3.0E-3 lb/GWh	
	Chromium (Cr)	2.8E0 lb/TBtu or 3.0E-2 lb/GWh	
	Cobalt (Co)	8.0E-1 lb/TBtu or 8.0E-3 lb/GWh	
	Lead (Pb)	1.2E0 lb/TBtu or 2.0E-2 lb/GWh	
	Manganese (Mn)	4.0E0 lb/TBtu or 5.0E-2 lb/GWh	
	Nickel (Ni)	3.5E0 lb/TBtu or 4.0E-2 lb/GWh	
	Selenium (Se)	5.0E0 lb/TBtu or 6.0E-2 lb/GWh	
	b. Hydrogen chloride (HCl)	2.0E-3 lb/MMBtu or 2.0E-2 lb/MWh	For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26 at appendix A-8 to part 60 of this chapter, collect a minimum of 120 liters per run. For ASTM D6348-03 <sup>3</sup> or Method 320, sample for a minimum of 1 hour.

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	OR		
	Sulfur dioxide (SO <sub>2</sub> ) <sup>4</sup>	2.0E-1 lb/MMBtu or 1.5E0 lb/MWh	SO <sub>2</sub> CEMS.
	c. Mercury (Hg)	4.0E0 lb/TBtu or 4.0E-2 lb/GWh	LEE Testing for 30 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
3. IGCC unit	a. Filterable particulate matter (PM)	4.0E-2 lb/MMBtu or 4.0E-1 lb/MWh <sup>2</sup>	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	6.0E-5 lb/MMBtu or 5.0E-1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	1.4E0 lb/TBtu or 2.0E-2 lb/GWh	
	Arsenic (As)	1.5E0 lb/TBtu or 2.0E-2 lb/GWh	
	Beryllium (Be)	1.0E-1 lb/TBtu or 1.0E-3 lb/GWh	
	Cadmium (Cd)	1.5E-1 lb/TBtu or 2.0E-3 lb/GWh	
	Chromium (Cr)	2.9E0 lb/TBtu or 3.0E-2 lb/GWh	
	Cobalt (Co)	1.2E0 lb/TBtu or 2.0E-2 lb/GWh	
	Lead (Pb)	1.9E+2 lb/TBtu or 1.8E0 lb/GWh	
	Manganese (Mn)	2.5E0 lb/TBtu or 3.0E-2 lb/GWh	
	Nickel (Ni)	6.5E0 lb/TBtu or 7.0E-2 lb/GWh	
	Selenium (Se)	2.2E+1 lb/TBtu or 3.0E-1 lb/GWh	
	b. Hydrogen chloride (HCl)	5.0E-4 lb/MMBtu or 5.0E-3 lb/MWh	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348-03 <sup>3</sup> or Method 320, sample for a minimum of 1 hour.

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	c. Mercury (Hg)	2.5E0 lb/TBtu or 3.0E-2 lb/GWh	LEE Testing for 30 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
4. Liquid oil-fired unit—continental (excluding limited-use liquid oil-fired subcategory units)	a. Filterable particulate matter (PM)	3.0E-2 lb/MMBtu or 3.0E-1 lb/MWh <sup>2</sup>	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	8.0E-4 lb/MMBtu or 8.0E-3 lb/MWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 1 dscm per run.
	Antimony (Sb)	1.3E+1 lb/TBtu or 2.0E-1 lb/GWh	
	Arsenic (As)	2.8E0 lb/TBtu or 3.0E-2 lb/GWh	
	Beryllium (Be)	2.0E-1 lb/TBtu or 2.0E-3 lb/GWh	
	Cadmium (Cd)	3.0E-1 lb/TBtu or 2.0E-3 lb/GWh	
	Chromium (Cr)	5.5E0 lb/TBtu or 6.0E-2 lb/GWh	
	Cobalt (Co)	2.1E+1 lb/TBtu or 3.0E-1 lb/GWh	
	Lead (Pb)	8.1E0 lb/TBtu or 8.0E-2 lb/GWh	
	Manganese (Mn)	2.2E+1 lb/TBtu or 3.0E-1 lb/GWh	
	Nickel (Ni)	1.1E+2 lb/TBtu or 1.1E0 lb/GWh	
	Selenium (Se)	3.3E0 lb/TBtu or 4.0E-2 lb/GWh	
	Mercury (Hg)	2.0E-1 lb/TBtu or 2.0E-3 lb/GWh	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be < 1/2 the standard.
	b. Hydrogen chloride (HCl)	2.0E-3 lb/MMBtu or 1.0E-2 lb/MWh	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348-03 <sup>3</sup> or Method 320, sample for a minimum of 1 hour.

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

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	c. Hydrogen fluoride (HF)	6.0E-5 lb/MMBtu or 5.0E-4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348-03 <sup>3</sup> or Method 320, sample for a minimum of 2 hours.
6. Solid oil-derived fuel-fired unit	a. Filterable particulate matter (PM)	8.0E-3 lb/MMBtu or 9.0E-2 lb/MWh <sup>2</sup>	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	4.0E-5 lb/MMBtu or 6.0E-1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E-1 lb/TBtu or 7.0E-3 lb/GWh	
	Arsenic (As)	3.0E-1 lb/TBtu or 5.0E-3 lb/GWh	
	Beryllium (Be)	6.0E-2 lb/TBtu or 5.0E-4 lb/GWh	
	Cadmium (Cd)	3.0E-1 lb/TBtu or 4.0E-3 lb/GWh	
	Chromium (Cr)	8.0E-1 lb/TBtu or 2.0E-2 lb/GWh	
	Cobalt (Co)	1.1E0 lb/TBtu or 2.0E-2 lb/GWh	
	Lead (Pb)	8.0E-1 lb/TBtu or 2.0E-2 lb/GWh	
	Manganese (Mn)	2.3E0 lb/TBtu or 4.0E-2 lb/GWh	
	Nickel (Ni)	9.0E0 lb/TBtu or 2.0E-1 lb/GWh	
	Selenium (Se)	1.2E0 lb/Tbtu or 2.0E-2 lb/GWh	
	b. Hydrogen chloride (HCl)	5.0E-3 lb/MMBtu or 8.0E-2 lb/MWh	For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348-03 <sup>3</sup> or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO <sub>2</sub> ) <sup>4</sup>	3.0E-1 lb/MMBtu or 2.0E0 lb/MWh	SO <sub>2</sub> CEMS.
	c. Mercury (Hg)	2.0E-1 lb/TBtu or 2.0E-3 lb/GWh	LEE Testing for 30 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B run or Hg CEMS or sorbent trap monitoring system only.



If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
7. Eastern Bituminous Coal Refuse (EBCR)-fired unit	a. Filterable particulate matter (PM)	3.0E-2 lb/MMBtu or 3.0E-1 lb/MWh <sup>2</sup>	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	5.0E-5 lb/MMBtu or 5.0E-1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E-1 lb/TBtu or 8.0E-3 lb/GWh	
	Arsenic (As)	1.1E0 lb/TBtu or 2.0E-2 lb/GWh	
	Beryllium (Be)	2.0E-1 lb/TBtu or 2.0E-3 lb/GWh	
	Cadmium (Cd)	3.0E-1 lb/TBtu or 3.0E-3 lb/GWh	
	Chromium (Cr)	2.8E0 lb/TBtu or 3.0E-2 lb/GWh	
	Cobalt (Co)	8.0E-1 lb/TBtu or 8.0E-3 lb/GWh	
	Lead (Pb)	1.2E0 lb/TBtu or 2.0E-2 lb/GWh	
	Manganese (Mn)	4.0E0 lb/TBtu or 5.0E-2 lb/GWh	
	Nickel (Ni)	3.5E0 lb/TBtu or 4.0E-2 lb/GWh	
	Selenium (Se)	5.0E0 lb/TBtu or 6.0E-2 lb/GWh	
	b. Hydrogen chloride (HCl)	4.0E-2 lb/MMBtu or 4.0E-1 lb/MWh	For Method 26A at appendix A-8 to part 60 of this chapter, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348-03 <sup>3</sup> or Method 320 at appendix A to part 63 of this chapter, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO <sub>2</sub> ) <sup>4</sup>	6E-1 lb/MMBtu or 9E0 lb/MWh	SO <sub>2</sub> CEMS.
	c. Mercury (Hg)	1.2E0 lb/TBtu or 1.3E-2 lb/GWh	LEE Testing for 30 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B at appendix A-8 to part 60 of this chapter run or Hg CEMS or sorbent trap monitoring system only.

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
		OR	
		1.0E0 lb/TBtu or 1.1E-2 lb/GWh	LEE Testing for 90 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B run or Hg CEMS or sorbent trap monitoring system only.

<sup>1</sup> For LEE emissions testing for total PM, total HAP metals, individual HAP metals, HCl, and HF, the required minimum sampling volume must be increased nominally by a factor of 2.

<sup>2</sup> Gross output.

<sup>3</sup> Incorporated by reference, see § 63.14.

<sup>4</sup> You may not use the alternate SO<sub>2</sub> limit if your EGU does not have some form of FGD system and SO<sub>2</sub> CEMS installed.

[85 FR 20850, Apr. 15, 2020]

**Table 3 to Subpart UUUUU of Part 63—Work Practice Standards**

As stated in §§ 63.9991, you must comply with the following applicable work practice standards:

If your EGU is . . .	You must meet the following . . .
1. An existing EGU	Conduct a tune-up of the EGU burner and combustion controls at least each 36 calendar months, or each 48 calendar months if neural network combustion optimization software is employed, as specified in § 63.10021(e).
2. A new or reconstructed EGU	Conduct a tune-up of the EGU burner and combustion controls at least each 36 calendar months, or each 48 calendar months if neural network combustion optimization software is employed, as specified in § 63.10021(e).
3. A coal-fired, liquid oil-fired (excluding limited-use liquid oil-fired subcategory units), or solid oil-derived fuel-fired EGU during startup	<p>a. You have the option of complying using either of the following work practice standards:</p> <p>(1) If you choose to comply using paragraph (1) of the definition of “startup” in § 63.10042, you must operate all CMS during startup. Startup means either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on site use). For startup of a unit, you must use clean fuels as defined in § 63.10042 for ignition. Once you convert to firing coal, residual oil, or solid oil-derived fuel, you must engage all of the applicable control technologies except dry scrubber and SCR. You must start your dry scrubber and SCR systems, if present, appropriately to comply with relevant standards applicable during normal operation. You must comply with all applicable emissions limits at all times except for periods that meet the applicable definitions of startup and shutdown in this subpart. You must keep records during startup periods. You must provide reports concerning activities and startup periods, as specified in § 63.10011(g) and § 63.10021(h) and (i). If you elect to use paragraph (2) of the definition of startup in 40 CFR 63.10042, you must report the applicable information in 40 CFR 63.10031(c)(5) concerning startup periods as follows: For startup periods that occur on or prior to December 31, 2023, in PDF files in the semiannual compliance report; for startup periods that occur on or after January 1, 2024, quarterly, in PDF files, according to 40 CFR 63.10031(i).</p>

If your EGU is . . .	You must meet the following . . .
	(2) If you choose to comply using paragraph (2) of the definition of “startup” in § 63.10042, you must operate all CMS during startup. You must also collect appropriate data, and you must calculate the pollutant emission rate for each hour of startup.
	For startup of an EGU, you must use one or a combination of the clean fuels defined in § 63.10042 to the maximum extent possible, taking into account considerations such as boiler or control device integrity, throughout the startup period. You must have sufficient clean fuel capacity to engage and operate your PM control device within one hour of adding coal, residual oil, or solid oil-derived fuel to the unit. You must meet the startup period work practice requirements as identified in § 63.10020(e).
	Once you start firing coal, residual oil, or solid oil-derived fuel, you must vent emissions to the main stack(s). You must comply with the applicable emission limits beginning with the hour after startup ends. You must engage and operate your PM control(s) within 1 hour of first firing of coal, residual oil, or solid oil-derived fuel.
	You must start all other applicable control devices as expeditiously as possible, considering safety and manufacturer/supplier recommendations, but, in any case, when necessary to comply with other standards made applicable to the EGU by a permit limit or a rule other than this subpart that require operation of the control devices.
	b. Relative to the syngas not fired in the combustion turbine of an IGCC EGU during startup, you must either: (1) Flare the syngas, or (2) route the syngas to duct burners, which may need to be installed, and route the flue gas from the duct burners to the heat recovery steam generator.
	c. If you choose to use just one set of sorbent traps to demonstrate compliance with the applicable Hg emission limit, you must comply with the limit at all times; otherwise, you must comply with the applicable emission limit at all times except for startup and shutdown periods.
	d. You must collect monitoring data during startup periods, as specified in § 63.10020(a) and (e). You must keep records during startup periods, as provided in §§ 63.10021(h) and 63.10032. You must provide reports concerning activities and startup periods, as specified in §§ 63.10011(g), 63.10021(i), and 63.10031. If you elect to use paragraph (2) of the definition of startup in 40 CFR 63.10042, you must report the applicable information in 40 CFR 63.10031(c)(5) concerning startup periods as follows: For startup periods that occur on or prior to December 31, 2023, in PDF files in the semiannual compliance report; for startup periods that occur on or after January 1, 2024, quarterly, in PDF files, according to 40 CFR 63.10031(i).
4. A coal-fired, liquid oil-fired (excluding limited-use liquid oil-fired subcategory units), or solid oil-derived fuel-fired EGU during shutdown	You must operate all CMS during shutdown. You must also collect appropriate data, and you must calculate the pollutant emission rate for each hour of shutdown for those pollutants for which a CMS is used. While firing coal, residual oil, or solid oil-derived fuel during shutdown, you must vent emissions to the main stack(s) and operate all applicable control devices and continue to operate those control devices after the cessation of coal, residual oil, or solid oil-derived fuel being fed into the EGU and for as long as possible thereafter considering operational and safety concerns. In any case, you must operate your controls when necessary to comply with other standards made applicable to the EGU by a permit limit or a rule other than this subpart and that require operation of the control devices.
	If, in addition to the fuel used prior to initiation of shutdown, another fuel must be used to support the shutdown process, that additional fuel must be one or a combination of the clean fuels defined in § 63.10042 and must be used to the maximum extent possible, taking into account considerations such as not compromising boiler or control device integrity.
	Relative to the syngas not fired in the combustion turbine of an IGCC EGU during shutdown, you must either: (1) Flare the syngas, or (2) route the syngas to duct burners, which may need to be installed, and route the flue gas from the duct burners to the heat recovery steam generator.

If your EGU is . . .	You must meet the following . . .
	<p>You must comply with all applicable emission limits at all times except during startup periods and shutdown periods at which time you must meet this work practice. You must collect monitoring data during shutdown periods, as specified in § 63.10020(a). You must keep records during shutdown periods, as provided in §§ 63.10032 and 63.10021(h). Any fraction of an hour in which shutdown occurs constitutes a full hour of shutdown. You must provide reports concerning activities and shutdown periods, as specified in §§ 63.10011(g), 63.10021(i), and 63.10031. If you elect to use paragraph (2) of the definition of startup in 40 CFR 63.10042, you must report the applicable information in 40 CFR 63.10031(c)(5) concerning shutdown periods as follows: For shutdown periods that occur on or prior to December 31, 2023, in PDF files in the semiannual compliance report; for shutdown periods that occur on or after January 1, 2024, quarterly, in PDF files, according to 40 CFR 63.10031(i).</p>

[81 FR 20196, Apr. 6, 2016, as amended at 85 FR 55763, Sept. 9, 2020]

**Table 4 to Subpart UUUUU of Part 63—Operating Limits for EGUs**

As stated in § 63.9991, you must comply with the applicable operating limits:

If you demonstrate compliance using . . .	You must meet these operating limits . . .
PM CPMS	<p>Maintain the 30-boiler operating day rolling average PM CPMS output determined in accordance with the requirements of § 63.10023(b)(2) and obtained during the most recent performance test run demonstrating compliance with the filterable PM, total non-mercury HAP metals (total HAP metals, for liquid oil-fired units), or individual non-mercury HAP metals (individual HAP metals including Hg, for liquid oil-fired units) emissions limitation(s).</p>

[81 FR 20197, Apr. 6, 2016]

**Table 5 to Subpart UUUUU of Part 63—Performance Testing Requirements**

As stated in § 63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources:<sup>1</sup>

To conduct a performance test for the following pollutant . . .	Using . . .	You must perform the following activities, as applicable to your input- or output-based emission limit . . .	Using . . . <sup>2</sup>
1. Filterable Particulate matter (PM)	Emissions Testing	a. Select sampling ports location and the number of traverse points	Method 1 at appendix A-1 to part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G or 2H at appendix A-1 or A-2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981. <sup>3</sup>
		d. Measure the moisture content of the stack gas	Method 4 at appendix A-3 to part 60 of this chapter.
		e. Measure the filterable PM concentration	Methods 5 and 5I at appendix A-3 to part 60 of this chapter. For positive pressure fabric filters, method 5D at appendix A-3 to part 60 of this chapter for filterable PM emissions. Note that the method 5 or 5I front half temperature shall be 160° ±14 °C (320° ±25 °F).
		f. Convert emissions concentration to lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter or calculate using mass emissions rate and gross output data (see § 63.10007(c)).
	OR	OR	
	PM CEMS	a. Install, certify, operate, and maintain the PM CEMS	Performance Specification 11 at appendix B to part 60 of this chapter and Procedure 2 at appendix F to part 60 of this chapter.
		b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or	Part 75 of this chapter and § 63.10010(a) through (d).

		moisture monitoring systems	
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
2. Total or individual non-Hg HAP metals	Emissions Testing	a. Select sampling ports location and the number of traverse points	Method 1 at appendix A-1 to part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G or 2H at appendix A-1 or A-2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981. <sup>3</sup>
		d. Measure the moisture content of the stack gas	Method 4 at appendix A-3 to part 60 of this chapter.
		e. Measure the HAP metals emissions concentrations and determine each individual HAP metals emissions concentration, as well as the total filterable HAP metals emissions concentration and total HAP metals emissions concentration	Method 29 at appendix A-8 to part 60 of this chapter. For liquid oil-fired units, Hg is included in HAP metals and you may use method 29, method 30B at appendix A-8 to part 60 of this chapter or ASTM D6784-16, <sup>3</sup> for method 29 or ASTM D 6784-16, you must report the front half and back half results separately. When using method 29, report metals matrix spike and recovery levels.
		f. Convert emissions concentrations (individual HAP metals, total filterable HAP metals, and total HAP metals) to lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
3. Hydrogen chloride (HCl) and hydrogen fluoride (HF)	Emissions Testing	a. Select sampling ports location and the number of traverse points	Method 1 at appendix A-1 to part 60 of this chapter.

		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G or 2H at appendix A-1 or A-2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981. <sup>3</sup>
		d. Measure the moisture content of the stack gas	Method 4 at appendix A-3 to part 60 of this chapter.
		e. Measure the HCl and HF emissions concentrations	Method 26 or method 26A at appendix A-8 to part 60 of this chapter or method 320 at appendix A to part 63 of this chapter or ASTM D6348-03(R2010) <sup>3</sup> with
			(1) the following conditions when using ASTM D6348-03(R2010):
			(A) The test plan preparation and implementation in the Annexes to ASTM D6348-03(R2010), sections A1 through A8 are mandatory;
			(B) For ASTM D6348-03(R2010) Annex A5 (Analyte Spiking Technique), the percent (%) R must be determined for each target analyte (see Equation A5.5);
			(C) For the ASTM D6348-03(R2010) test data to be acceptable for a target analyte, %R must be $70\% \geq R \leq 130\%$ ; and
			(D) The %R value for each compound must be reported in the test report and all field measurements corrected with the calculated %R value for that compound using the following equation:  $\text{Report Result} = \frac{(\text{Measured Concentration in Stack})}{\%R} \times 100$

To conduct a performance test for the following pollutant . . . (cont'd)	Using . . . (cont'd)	You must perform the following activities, as applicable to your input- or output-based emission limit . . . (cont'd)	Using . . . <sup>2</sup> (cont'd)
			(2) spiking levels nominally no greater than two times the level corresponding to the applicable emission limit.
			Method 26A must be used if there are entrained water droplets in the exhaust stream.
		f. Convert emissions concentration to lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
	OR	OR	
	HCl and/or HF CEMS	a. Install, certify, operate, and maintain the HCl or HF CEMS	Appendix B of this subpart.
		b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	Part 75 of this chapter and § 63.10010(a) through (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
4. Mercury (Hg)	Emissions Testing	a. Select sampling ports location and the number of traverse points	Method 1 at appendix A-1 to part 60 of this chapter or method 30B at appendix A-8 for method 30B point selection.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G or 2H at appendix A-1 or A-2 to part 60 of this chapter.



		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at appendix A-1 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981. <sup>3</sup>
		d. Measure the moisture content of the stack gas	Method 4 at appendix A-3 to part 60 of this chapter.
		e. Measure the Hg emission concentration	Method 30B at appendix A-8 to part 60 of this chapter, ASTM D6784-16, <sup>3</sup> or method 29 at appendix A-8 to part 60 of this chapter; for method 29 or ASTM D 6784-16, you must report the front half and back half results separately.
		f. Convert emissions concentration to lb/TBtu or lb/GWh emission rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
	OR	OR	
	Hg CEMS	a. Install, certify, operate, and maintain the CEMS	Sections 3.2.1 and 5.1 of appendix A of this subpart.
		b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	Part 75 of this chapter and § 63.10010(a) through (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/TBtu or lb/GWh emissions rates	Section 6 of appendix A to this subpart.
	OR	OR	
	Sorbent trap monitoring system	a. Install, certify, operate, and maintain the sorbent trap monitoring system	Sections 3.2.2 and 5.2 of appendix A to this subpart.

		b. Install, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	Part 75 of this chapter and § 63.10010(a) through (d).
		c. Convert emissions concentrations to 30 boiler operating day rolling average lb/TBtu or lb/GWh emissions rates	Section 6 of appendix A to this subpart.
	OR	OR	
	LEE testing	a. Select sampling ports location and the number of traverse points	Single point located at the 10% centroidal area of the duct at a port location per method 1 at appendix A-1 to part 60 of this chapter or method 30B at appendix A-8 to part 60 of this chapter for method 30B point selection.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G, or 2H at appendix A-1 or A-2 to part 60 of this chapter or flow monitoring system certified per appendix A of this subpart.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at appendix A-1 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981, <sup>3</sup> or diluent gas monitoring systems certified according to part 75 of this chapter.
		d. Measure the moisture content of the stack gas	Method 4 at appendix A-3 to part 60 of this chapter, or moisture monitoring systems certified according to part 75 of this chapter.
		e. Measure the Hg emission concentration	Method 30B at appendix A-8 to part 60 of this chapter; perform a 30 operating day test, with a maximum of 10 operating days per run ( <i>i.e.</i> , per pair of sorbent traps) or sorbent trap monitoring system or Hg CEMS certified per appendix A of this subpart.
		f. Convert emissions concentrations from	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter

		the LEE test to lb/TBtu or lb/GWh emissions rates	or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
		g. Convert average lb/TBtu or lb/GWh Hg emission rate to lb/year, if you are attempting to meet the 29.0 lb/year threshold	Potential maximum annual heat input in TBtu or potential maximum electricity generated in GWh.
5. Sulfur dioxide (SO <sub>2</sub> )	SO <sub>2</sub> CEMS	a. Install, certify, operate, and maintain the CEMS	Part 75 of this chapter and § 63.10010(a) and (f).
		b. Install, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	Part 75 of this chapter and § 63.10010(a) through (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter or calculate using mass emissions rate and gross output data (see § 63.10007(e)).

<sup>1</sup> Regarding emissions data collected during periods of startup or shutdown, see §§ 63.10020(b) and (c) and 63.10021(h).

<sup>2</sup> See tables 1 and 2 to this subpart for required sample volumes and/or sampling run times.

<sup>3</sup> Incorporated by reference, see § 63.14.

**Table 6 to Subpart UUUUU of Part 63—Establishing PM CPMS Operating Limits**

As stated in § 63.10007, you must comply with the following requirements for establishing operating limits:

If you have an applicable emission limit for . . .	And you choose to establish PM CPMS operating limits, you must . . .	And . . .	Using . . .	According to the following procedures . . .
Filterable Particulate matter (PM), total non-mercury HAP metals, individual non-mercury HAP metals, total HAP metals, or individual HAP metals for an EGU	Install, certify, maintain, and operate a PM CPMS for monitoring emissions discharged to the atmosphere according to § 63.10010(h)(1)	Establish a site-specific operating limit in units of PM CPMS output signal (e.g., milliamps, mg/acm, or other raw signal)	Data from the PM CPMS and the PM or HAP metals performance tests	<ol style="list-style-type: none"> <li>1. Collect PM CPMS output data during the entire period of the performance tests.</li> <li>2. Record the average hourly PM CPMS output for each test run in the performance test.</li> <li>3. Determine the PM CPMS operating limit in accordance with the requirements of § 63.10023(b)(2) from data obtained during the performance test demonstrating compliance with the filterable PM or HAP metals emissions limitations.</li> </ol>

[81 FR 20201, Apr. 6, 2016]

**Table 7 to Subpart UUUUU of Part 63—Demonstrating Continuous Compliance**

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

If you use one of the following to meet applicable emissions limits, operating limits, or work practice standards . . .	You demonstrate continuous compliance by . . .
1. CEMS to measure filterable PM, SO <sub>2</sub> , HCl, HF, or Hg emissions, or using a sorbent trap monitoring system to measure Hg	Calculating the 30- (or 90-) boiler operating day rolling arithmetic average emissions rate in units of the applicable emissions standard basis at the end of each boiler operating day using all of the quality assured hourly average CEMS or sorbent trap data for the previous 30- (or 90-) boiler operating days, excluding data recorded during periods of startup or shutdown.
2. PM CPMS to measure compliance with a parametric operating limit	Calculating the 30- (or 90-) boiler operating day rolling arithmetic average of all of the quality assured hourly average PM CPMS output data (e.g., milliamps, PM concentration, raw data signal) collected for all operating hours for the previous 30- (or 90-) boiler operating days, excluding data recorded during periods of startup or shutdown.
3. Site-specific monitoring using CMS for liquid oil-fired EGUs for HCl and HF emission limit monitoring	If applicable, by conducting the monitoring in accordance with an approved site-specific monitoring plan.

<b>If you use one of the following to meet applicable emissions limits, operating limits, or work practice standards . . .</b>	<b>You demonstrate continuous compliance by . . .</b>
4. Quarterly performance testing for coal-fired, solid oil derived fired, or liquid oil-fired EGUs to measure compliance with one or more non-PM (or its alternative emission limits) applicable emissions limit in Table 1 or 2, or PM (or its alternative emission limits) applicable emissions limit in Table 2	Calculating the results of the testing in units of the applicable emissions standard.
5. Conducting periodic performance tune-ups of your EGU(s)	Conducting periodic performance tune-ups of your EGU(s), as specified in § 63.10021(e).
6. Work practice standards for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs during startup	Operating in accordance with Table 3.
7. Work practice standards for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs during shutdown	Operating in accordance with Table 3.

[78 FR 24092, Apr. 24, 2013]

**Table 8 to Subpart UUUUU of Part 63—Reporting Requirements**

[In accordance with 40 CFR 63.10031, you must meet the following reporting requirements, as they apply to your compliance strategy]

<b>You must submit the following reports . . .</b>
1. The electronic reports required under 40 CFR 63.10031 (a)(1), if you continuously monitor Hg emissions.
2. The electronic reports required under 40 CFR 63.10031 (a)(2), if you continuously monitor HCl and/or HF emissions.
Where applicable, these reports are due no later than 30 days after the end of each calendar quarter.
3. The electronic reports required under 40 CFR 63.10031(a)(3), if you continuously monitor PM emissions.
Reporting of hourly PM emissions data using ECMPS shall begin with the first operating hour after: January 1, 2024, or the hour of completion of the initial PM CEMS correlation test, whichever is later.
Where applicable, these reports are due no later than 30 days after the end of each calendar quarter.
4. The electronic reports required under 40 CFR 63.10031(a)(4), if you elect to use a PM CPMS.
Reporting of hourly PM CPMS response data using ECMPS shall begin with the first operating hour after January 1, 2024, or the first operating hour after completion of the initial performance stack test that establishes the operating limit for the PM CPMS, whichever is later.
Where applicable, these reports are due no later than 30 days after the end of each calendar quarter.
5. The electronic reports required under 40 CFR 63.10031(a)(5), if you continuously monitor SO <sub>2</sub> emissions.
Where applicable, these reports are due no later than 30 days after the end of each calendar quarter.
6. PDF reports for all performance stack tests completed prior to January 1, 2024 (including 30- or 90-boiler operating day Hg LEE test reports and PM test reports to set operating limits for PM CPMS), according to the introductory text of 40 CFR 63.10031(f) and 40 CFR 63.10031(f)(6).
For each test, submit the PDF report no later than 60 days after the date on which testing is completed.
For a PM test that is used to set an operating limit for a PM CPMS, the report must also include the information in 40 CFR 63.10023(b)(2)(vi).

<b>You must submit the following reports . . .</b>
For each performance stack test completed on or after January 1, 2024, submit the test results in the relevant quarterly compliance report under 40 CFR 63.10031(g), together with the applicable reference method information in sections 17 through 31 of appendix E to this subpart.
7. PDF reports for all RATAs of Hg, HCl, HF, and/or SO <sub>2</sub> monitoring systems completed prior to January 1, 2024, and for correlation tests, RRAs and/or RCAs of PM CEMS completed prior to January 1, 2024, according to 40 CFR 63.10031(f)(1) and (6).
For each test, submit the PDF report no later than 60 days after the date on which testing is completed.
For each SO <sub>2</sub> or Hg system RATA completed on or after January 1, 2024, submit the electronic test summary required by appendix A to this subpart or part 75 of this chapter (as applicable) together with the applicable reference method information in sections 17 through 30 of appendix E to this subpart, either prior to or concurrent with the relevant quarterly emissions report.
For each HCl or HF system RATA, and for each correlation test, RRA, and RCA of a PM CEMS completed on or after January 1, 2024, submit the electronic test summary in accordance with section 11.4 of appendix B to this subpart or section 7.2.4 of appendix C to this part, as applicable, together with the applicable reference method information in sections 17 through 30 of appendix E to this subpart.
8. Quarterly reports, in PDF files, that include all 30-boiler operating day rolling averages in the reporting period derived from your PM CEMS, approved HAP metals CEMS, and/or PM CPMS, according to 40 CFR 63.10031(f)(2) and (6). These reports are due no later than 60 days after the end of each calendar quarter.
The final quarterly rolling averages report in PDF files shall cover the fourth calendar quarter of 2023.
Starting with the first quarter of 2024, you must report all 30-boiler operating day rolling averages for PM CEMS, approved HAP metals CEMS, PM CPMS, Hg CEMS, Hg sorbent trap systems, HCl CEMS, HF CEMS, and/or SO <sub>2</sub> CEMS (or 90-boiler operating day rolling averages for Hg systems), in XML format, in the quarterly compliance reports required under 40 CFR 63.10031(g).
If your EGU or common stack is in an averaging plan, each quarterly compliance report must identify the EGUs in the plan and include all of the 30- or 90- group boiler operating day WAERs for the averaging group.
The quarterly compliance reports must be submitted no later than 60 days after the end of each calendar quarter.
9. The semiannual compliance reports described in 40 CFR 63.10031(c) and (d), in PDF files, according to 40 CFR 63.10031(f)(4) and (6). The due dates for these reports are specified in 40 CFR 63.10031(b).
The final semiannual compliance report shall cover the period from July 1, 2023, through December 31, 2023.
10. Notifications of compliance status, in PDF files, according to 40 CFR 63.10031(f)(4) and (6) until December 31, 2023, and according to 40 CFR 63.10031(h) thereafter.
11. Quarterly electronic compliance reports, in accordance with 40 CFR 63.10031(g), starting with a report for the first calendar quarter of 2024. The reports must be in XML format and must include the applicable data elements in sections 2 through 13 of appendix E to this subpart.
These reports are due no later than 60 days after the end of each calendar quarter.
12. Quarterly reports, in PDF files, that include the applicable information in 40 CFR 63.10031(c)(5)(ii) and 40 CFR 63.10020(e) pertaining to startup and shutdown events, starting with a report for the first calendar quarter of 2024, if you have elected to use paragraph 2 of the definition of startup in 40 CFR 63.10042 (see 40 CFR 63.10031(i)).
These PDF reports shall be submitted no later than 60 days after the end of each calendar quarter, along with the quarterly compliance reports required under 40 CFR 63.10031(g).
13. A test report for the PS 11 correlation test of your PM CEMS, in accordance with 40 CFR 63.10031(j).
If, prior to November 9, 2020, you have begun using a certified PM CEMS to demonstrate compliance with this subpart, use the ECMPS Client Tool to submit the report, in a PDF file, no later than 60 days after that date.
For correlation tests completed on or after November 9, 2020, but prior to January 1, 2024, submit the report, in a PDF file, no later than 60 days after the date on which the test is completed.

<b>You must submit the following reports . . .</b>
For correlation tests completed on or after January 1, 2024, submit the test results electronically, according to section 7.2.4 of appendix C to this subpart, together with the applicable reference method data in sections 17 through 31 of appendix E to this subpart.
14. Quarterly reports that include the QA/QC activities for your PM CPMS or approved HAP metals CEMS (as applicable), in PDF files, according to 40 CFR 63.10031(k).
The first report shall cover the first calendar quarter of 2024, if the PM CPMS or HAP metals CEMS is in use during that quarter. Otherwise, reporting begins with the first calendar quarter in which the PM CPMS or HAP metals CEMS is used to demonstrate compliance.
These reports are due no later than 60 days after the end of each calendar quarter.

[85 FR 55764, Sept. 9, 2020]

**Table 9 to Subpart UUUUU of Part 63—Applicability of General Provisions to Subpart UUUUU**

As stated in § 63.10040, you must comply with the applicable General Provisions according to the following:

<b>Citation</b>	<b>Subject</b>	<b>Applies to subpart UUUUU</b>
§ 63.1	Applicability	Yes.
§ 63.2	Definitions	Yes. Additional terms defined in § 63.10042.
§ 63.3	Units and Abbreviations	Yes.
§ 63.4	Prohibited Activities and Circumvention	Yes.
§ 63.5	Preconstruction Review and Notification Requirements	Yes.
§ 63.6(a), (b)(1) through (5), (b)(7), (c), (f)(2) and (3), (h)(2) through (9), (i), (j)	Compliance with Standards and Maintenance Requirements	Yes.
§ 63.6(e)(1)(i)	General Duty to minimize emissions	No. See § 63.10000(b) for general duty requirement.
§ 63.6(e)(1)(ii)	Requirement to correct malfunctions ASAP	No.
§ 63.6(e)(3)	SSM Plan requirements	No.
§ 63.6(f)(1)	SSM exemption	No.
§ 63.6(h)(1)	SSM exemption	No.
§ 63.6(g)	Compliance with Standards and Maintenance Requirements, Use of an alternative non-opacity emission standard	Yes. See §§ 63.10011(g)(4) and 63.10021(h)(4) for additional requirements.
§ 63.7(e)(1)	Performance testing	No. See § 63.10007.
§ 63.8	Monitoring Requirements	Yes.

Citation	Subject	Applies to subpart UUUUU
§ 63.8(c)(1)(i)	General duty to minimize emissions and CMS operation	No. See § 63.10000(b) for general duty requirement.
§ 63.8(c)(1)(iii)	Requirement to develop SSM Plan for CMS	No.
§ 63.8(d)(3)	Written procedures for CMS	Yes, except for last sentence, which refers to an SSM plan. SSM plans are not required.
§ 63.9	Notification Requirements	Yes, except (1) for the 60-day notification prior to conducting a performance test in § 63.9(e); instead use a 30-day notification period per § 63.10030(d), (2) the notification of the CMS performance evaluation in § 63.9(g)(1) is limited to RATAs, and (3) the information required per § 63.9(h)(2)(i); instead provide the applicable information in § 63.10030(e)(1) through (8), for the initial notification of compliance status, only.
§ 63.10(a), (b)(1), (c), (d)(1) and (2), (e), and (f)	Recordkeeping and Reporting Requirements	Yes, except for the requirements to submit written reports under § 63.10(e)(3)(v).
§ 63.10(b)(2)(i)	Recordkeeping of occurrence and duration of startups and shutdowns	No.
§ 63.10(b)(2)(ii)	Recordkeeping of malfunctions	No. See § 63.10001 for recordkeeping of (1) occurrence and duration and (2) actions taken during malfunction.
§ 63.10(b)(2)(iii)	Maintenance records	Yes.
§ 63.10(b)(2)(iv)	Actions taken to minimize emissions during SSM	No.
§ 63.10(b)(2)(v)	Actions taken to minimize emissions during SSM	No.
§ 63.10(b)(2)(vi)	Recordkeeping for CMS malfunctions	Yes.
§ 63.10(b)(2)(vii) through (ix)	Other CMS requirements	Yes.
§ 63.10(b)(3) and (d)(3) through (5)		No.
§ 63.10(c)(7)	Additional recordkeeping requirements for CMS — identifying exceedances and excess emissions	Applies only through December 31, 2023.
§ 63.10(c)(8)	Additional recordkeeping requirements for CMS— identifying exceedances and excess emissions	Applies only through December 31, 2023.
§ 63.10(c)(10)	Recording nature and cause of malfunctions	No. See § 63.10032(g) and (h) for malfunctions recordkeeping requirements.
§ 63.10(c)(11)	Recording corrective actions	No. See § 63.10032(g) and (h) for malfunctions recordkeeping requirements.
§ 63.10(c)(15)	Use of SSM Plan	No.
§ 63.10(d)(5)	SSM reports	No. See § 63.10021(h) and (i) for malfunction reporting requirements.



Citation	Subject	Applies to subpart UUUUU
§ 63.10(e)(3)(v) and (vi)	Excess emissions and CMS performance reports	Applies only through December 31, 2023.
§ 63.11	Control Device Requirements	No.
§ 63.12	State Authority and Delegation	Yes.
§§ 63.13 through 63.16	Addresses, Incorporation by Reference, Availability of Information, Performance Track Provisions	Yes.
§§ 63.1(a)(5),(a)(7) through (9), (b)(2), (c)(3) and (4), (d), 63.6(b)(6), (c)(3) and (4), (d), (e)(2), (e)(3)(ii), (h)(3), (h)(5)(iv), 63.8(a)(3), 63.9(b)(3), (h)(4), 63.10(c)(2) through (4), (c)(9).	Reserved	No.

[81 FR 20202, Apr. 6, 2016, as amended at 85 FR 55765, Sept. 9, 2020]

**Appendix A to Subpart UUUUU of Part 63—Hg Monitoring Provisions**

1. General Provisions

**1.1 Applicability.** These monitoring provisions apply to the measurement of total vapor phase mercury (Hg) in emissions from electric utility steam generating units, using either a mercury continuous emission monitoring system (Hg CEMS) or a sorbent trap monitoring system. The Hg CEMS or sorbent trap monitoring system must be capable of measuring the total vapor phase mercury in units of the applicable emissions standard (e.g., lb/TBtu or lb/GWh), regardless of speciation.

**1.2 Initial Certification and Recertification Procedures.** The owner or operator of an affected unit that uses a Hg CEMS or a sorbent trap monitoring system together with other necessary monitoring components to account for Hg emissions in units of the applicable emissions standard shall comply with the initial certification and recertification procedures in section 4 of this appendix.

**1.3 Quality Assurance and Quality Control Requirements.** The owner or operator of an affected unit that uses a Hg CEMS or a sorbent trap monitoring system together with other necessary monitoring components to account for Hg emissions in units of the applicable emissions standard shall meet the applicable quality assurance requirements in section 5 of this appendix.

**1.4 Missing Data Procedures.** The owner or operator of an affected unit is not required to substitute for missing data from Hg CEMS or sorbent trap monitoring systems. Any process operating hour for which quality-assured Hg concentration data are not obtained is counted as an hour of monitoring system downtime.

2. Monitoring of Hg Emissions

**2.1 Monitoring System Installation Requirements.** Flue gases from the affected units under this subpart vent to the atmosphere through a variety of exhaust configurations including single stacks, common stack configurations, and multiple stack configurations. For each of these configurations, § 63.10010(a) specifies the appropriate location(s) at which to install continuous monitoring systems (CMS). These CMS installation provisions apply to the Hg CEMS, sorbent trap monitoring systems, and other continuous monitoring systems that provide data for the Hg emissions calculations in section 6.2 of this appendix.

**2.2 Primary and Backup Monitoring Systems.** In the electronic monitoring plan described in section 7.1.1.2.1 of this appendix, you must designate a primary Hg CEMS or sorbent trap monitoring system. The primary system must be used to report hourly Hg concentration values when the system is able to provide quality-assured data, *i.e.*, when the system is “in control”. However, to increase data availability in the event of a primary monitoring system outage, you may install, operate, maintain, and calibrate backup monitoring systems, as follows:

**2.2.1 Redundant Backup Systems.** A redundant backup monitoring system may be either a separate Hg CEMS with its own probe, sample interface, and analyzer, or a separate sorbent trap monitoring system. A redundant backup system is one that is permanently installed at the unit or stack location, and is kept on “hot standby” in case the primary monitoring system is unable to provide quality-assured data. A redundant backup system must be represented as a unique monitoring system in the electronic monitoring plan. Each redundant backup monitoring system must be certified according to the applicable provisions in section 4 of this appendix and must meet the applicable on-going QA requirements in section 5 of this appendix.

**2.2.2 Non-redundant Backup Monitoring Systems.** A non-redundant backup monitoring system is a separate Hg CEMS or sorbent trap system that has been certified at a particular unit or stack location, but is not permanently installed at that location. Rather, the system is kept on “cold standby” and may be reinstalled in the event of a primary monitoring system outage. A non-redundant backup monitoring system must be represented as a unique monitoring system in the electronic monitoring plan. Non-redundant backup Hg CEMS must complete the same certification tests as the primary monitoring system, with one exception. The 7-day calibration error test is not required for a non-redundant backup Hg CEMS. Except as otherwise provided in section 2.2.4.5 of this appendix, a non-redundant backup monitoring system may only be used for 720 hours per year at a particular unit or stack location.

**2.2.3 Temporary Like-kind Replacement Analyzers.** When a primary Hg analyzer needs repair or maintenance, you may temporarily install a like-kind replacement analyzer, to minimize data loss. Except as otherwise provided in section 2.2.4.5 of this appendix, a temporary like-kind replacement analyzer may only be used for 720 hours per year at a particular unit or stack location. The analyzer must be represented as a component of the primary Hg CEMS, and must be assigned a 3-character component ID number, beginning with the prefix “LK”.

**2.2.4 Quality Assurance Requirements for Non-redundant Backup Monitoring Systems and Temporary Like-kind Replacement Analyzers.** To quality-assure the data from non-redundant backup Hg monitoring systems and temporary like-kind replacement Hg analyzers, the following provisions apply:

2.2.4.1 When a certified non-redundant backup sorbent trap monitoring system is brought into service, you must follow the procedures for routine day-to-day operation of the system, in accordance with Performance Specification (PS) 12B in appendix B to part 60 of this chapter.

2.2.4.2 When a certified non-redundant backup Hg CEMS or a temporary like-kind replacement Hg analyzer is brought into service, a calibration error test and a linearity check must be performed and passed. A single point system integrity check is also required, unless a NIST-traceable source of oxidized Hg was used for the calibration error test.

2.2.4.3 Each non-redundant backup Hg CEMS or temporary like-kind replacement Hg analyzer shall comply with all required daily, weekly, and quarterly quality-assurance test requirements in section 5 of this appendix, for as long as the system or analyzer remains in service.

2.2.4.4 For the routine, on-going quality-assurance of a non-redundant backup Hg monitoring system, a relative accuracy test audit (RATA) must be performed and passed at least once every 8 calendar quarters at the unit or stack location(s) where the system will be used.

2.2.4.5 To use a non-redundant backup Hg monitoring system or a temporary like-kind replacement analyzer for more than 720 hours per year at a particular unit or stack location, a RATA must first be performed and passed at that location.

### 3. Mercury Emissions Measurement Methods

The following definitions, equipment specifications, procedures, and performance criteria are applicable to the measurement of vapor-phase Hg emissions from electric utility steam generating units, under relatively low-dust conditions (*i.e.*, sampling in the stack or duct after all pollution control devices). The analyte measured by these procedures and specifications is total vapor-phase Hg in the flue gas, which represents the sum of elemental Hg (Hg<sup>0</sup>, CAS Number 7439-97-6) and oxidized forms of Hg.

#### 3.1 **Definitions.**

3.1.1 **Mercury Continuous Emission Monitoring System or Hg CEMS** means all of the equipment used to continuously determine the total vapor phase Hg concentration. The measurement system may include the following major subsystems: sample acquisition, Hg<sup>+2</sup> to Hg<sup>0</sup> converter, sample transport, sample conditioning, flow control/gas manifold, gas analyzer, and data acquisition and handling system (DAHS). Hg CEMS may be nominally real-time or time-integrated, batch sampling systems that sample the gas on an intermittent basis and concentrate on a collection medium before intermittent analysis and reporting.

3.1.2 **Sorbent Trap Monitoring System** means the equipment required to monitor Hg emissions continuously by using paired sorbent traps containing iodated charcoal (IC) or other suitable sorbent medium. The monitoring system consists of a probe, paired sorbent traps, an umbilical line, moisture removal components, an airtight sample pump, a gas flow meter, and an automated data acquisition and handling system. The system samples the stack gas at a constant proportional rate relative to the stack gas volumetric flow rate. The sampling is a batch process. The average Hg concentration in the stack gas for the sampling period is determined, in units of micrograms per dry standard cubic meter (µg/dscm), based on the sample volume measured by the gas flow meter and the mass of Hg collected in the sorbent traps.

3.1.3 **NIST** means the National Institute of Standards and Technology, located in Gaithersburg, Maryland.

3.1.4 **NIST-Traceable Elemental Hg Standards** means either: compressed gas cylinders having known concentrations of elemental Hg, which have been prepared according to the "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards"; or calibration gases having known concentrations of elemental Hg, produced by a generator that meets the performance requirements of the "EPA Traceability Protocol for Qualification and Certification of Elemental Mercury Gas Generators" or an interim version of that protocol.

3.1.5 **NIST-Traceable Source of Oxidized Hg** means a generator that is capable of providing known concentrations of vapor phase mercuric chloride (HgCl<sub>2</sub>), and that meets the performance requirements of the "EPA Traceability Protocol for Qualification and Certification of Mercuric Chloride Gas Generators" or an interim version of that protocol.

3.1.6 **Calibration Gas** means a NIST-traceable gas standard containing a known concentration of elemental or oxidized Hg that is produced and certified in accordance with an EPA traceability protocol.

3.1.7 **Span Value** means a conservatively high estimate of the Hg concentrations to be measured by a CEMS. The span value of a Hg CEMS should be set to approximately twice the concentration corresponding to the emission standard, rounded off as appropriate (see section 3.2.1.4.2 of this appendix).

3.1.8 **Zero-Level Gas** means calibration gas containing a Hg concentration that is below the level detectable by the Hg gas analyzer in use.

3.1.9 **Low-Level Gas** means calibration gas with a concentration that is 20 to 30 percent of the span value.

3.1.10 **Mid-Level Gas** means calibration gas with a concentration that is 50 to 60 percent of the span value.

3.1.11 **High-Level Gas** means calibration gas with a concentration that is 80 to 100 percent of the span value.

3.1.12 **Calibration Error Test** means a test designed to assess the ability of a Hg CEMS to measure the concentrations of calibration gases accurately. A zero-level gas and an upscale gas are required for this test. For the upscale gas, either a mid-level gas or a high-level gas may be used, and the gas may either be an elemental or oxidized Hg standard.

3.1.13 **Linearity Check** means a test designed to determine whether the response of a Hg analyzer is linear across its measurement range. Three elemental Hg calibration gas standards (*i.e.*, low, mid, and high-level gases) are required for this test.

3.1.14 **System Integrity Check** means a test designed to assess the transport and measurement of oxidized Hg by a Hg CEMS. Oxidized Hg standards are used for this test. For a three-level system integrity check, low, mid, and high-level calibration gases are required. For a single-level check, either a mid-level gas or a high-level gas may be used.

3.1.15 **Cycle Time Test** means a test designed to measure the amount of time it takes for a Hg CEMS, while operating normally, to respond to a known step change in gas concentration. For this test, a zero gas and a high-level gas are required. The high-level gas may be either an elemental or an oxidized Hg standard.

3.1.16 **Relative Accuracy Test Audit or RATA** means a series of nine or more test runs, directly comparing readings from a Hg CEMS or sorbent trap monitoring system to measurements made with a reference stack test method. The relative accuracy (RA) of the monitoring system is expressed as the absolute mean difference between the monitoring system and reference method measurements plus the absolute value of the 2.5 percent error confidence coefficient, divided by the mean value of the reference method measurements.

3.1.17 **Unit Operating Hour** means a clock hour in which a unit combusts any fuel, either for part of the hour or for the entire hour.

3.1.18 **Stack Operating Hour** means a clock hour in which gases flow through a particular monitored stack or duct (either for part of the hour or for the entire hour), while the associated unit(s) are combusting fuel.

3.1.19 **Operating Day** means a calendar day in which a source combusts any fuel.

3.1.20 **Quality Assurance (QA) Operating Quarter** means a calendar quarter in which there are at least 168 unit or stack operating hours (as defined in this section).

3.1.21 **Grace Period** means a specified number of unit or stack operating hours after the deadline for a required quality-assurance test of a continuous monitor has passed, in which the test may be performed and passed without loss of data.

### 3.2 **Continuous Monitoring Methods.**

3.2.1 **Hg CEMS.** A typical Hg CEMS is shown in Figure A-1. The CEMS in Figure A-1 is a dilution extractive system, which measures Hg concentration on a wet basis, and is the most commonly-used type of Hg CEMS. Other system designs may be used, provided that the CEMS meets the performance specifications in section 4.1.1 of this appendix.

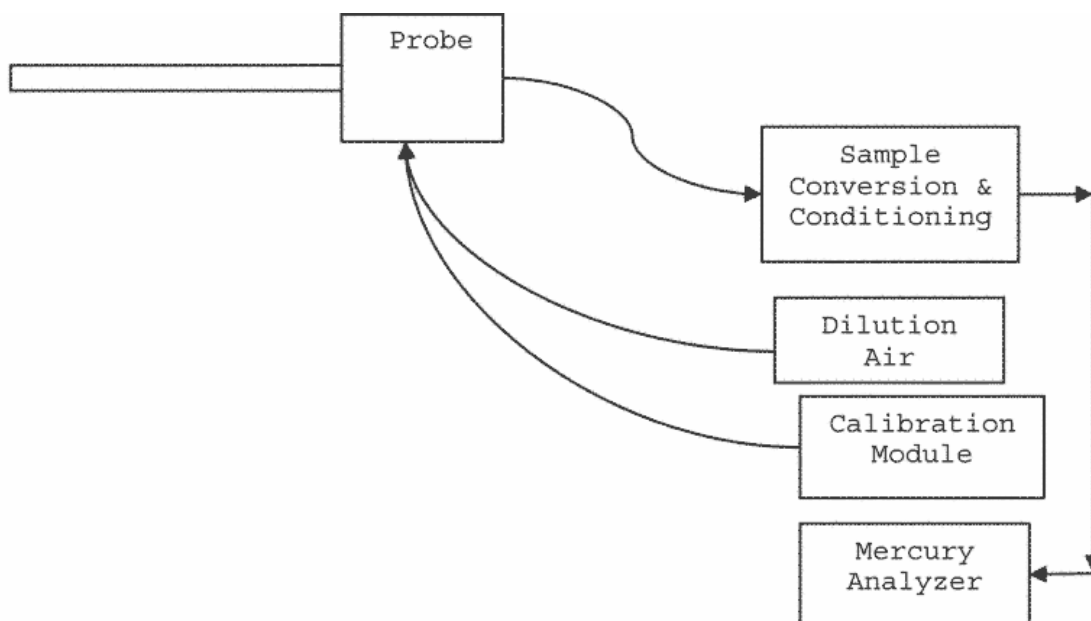


FIGURE A-1. TYPICAL MERCURY CEMS

### 3.2.1.1 *Equipment Specifications.*

3.2.1.1.1 **Materials of Construction.** All wetted sampling system components, including probe components prior to the point at which the calibration gas is introduced, must be chemically inert to all Hg species. Materials such as perfluoroalkoxy (PFA) Teflon™, quartz, and treated stainless steel (SS) are examples of such materials.

3.2.1.1.2 **Temperature Considerations.** All system components prior to the Hg<sup>+2</sup> to Hg<sup>0</sup> converter must be maintained at a sample temperature above the acid gas dew point.

### 3.2.1.1.3 *Measurement System Components.*

3.2.1.1.3.1 **Sample Probe.** The probe must be made of the appropriate materials as noted in paragraph 3.2.1.1.1 of this section, heated when necessary, as described in paragraph 3.2.1.1.3.4 of this section, and configured with ports for introduction of calibration gases.

3.2.1.1.3.2 **Filter or Other Particulate Removal Device.** The filter or other particulate removal device is part of the measurement system, must be made of appropriate materials, as noted in paragraph 3.2.1.1.1 of this section, and must be included in all system tests.

3.2.1.1.3.3 **Sample Line.** The sample line that connects the probe to the converter, conditioning system, and analyzer must be made of appropriate materials, as noted in paragraph 3.2.1.1.1 of this section.

3.2.1.1.3.4 **Conditioning Equipment.** For wet basis systems, such as the one shown in Figure A-1, the sample must be kept above its dew point either by: heating the sample line and all sample transport components up to the inlet of the analyzer (and, for hot-wet extractive systems, also heating the analyzer); or diluting the sample prior to analysis using a dilution probe system. The components required for these operations are considered to be conditioning equipment. For dry basis measurements, a condenser, dryer or other suitable device is required to remove moisture continuously

from the sample gas, and any equipment needed to heat the probe or sample line to avoid condensation prior to the moisture removal component is also required.

**3.2.1.1.3.5 Sampling Pump.** A pump is needed to push or pull the sample gas through the system at a flow rate sufficient to minimize the response time of the measurement system. If a mechanical sample pump is used and its surfaces are in contact with the sample gas prior to detection, the pump must be leak free and must be constructed of a material that is non-reactive to the gas being sampled (see paragraph 3.2.1.1.1 of this section). For dilution-type measurement systems, such as the system shown in Figure A–1, an ejector pump (eductor) may be used to create a sufficient vacuum that sample gas will be drawn through a critical orifice at a constant rate. The ejector pump must be constructed of any material that is non-reactive to the gas being sampled.

**3.2.1.1.3.6 Calibration Gas System(s).** Design and equip each Hg CEMS to permit the introduction of known concentrations of elemental Hg and HgCl<sub>2</sub> separately, at a point preceding the sample extraction filtration system, such that the entire measurement system can be checked. The calibration gas system(s) must be designed so that the flow rate exceeds the sampling system flow requirements and that the gas is delivered to the CEMS at atmospheric pressure.

**3.2.1.1.3.7 Sample Gas Delivery.** The sample line may feed directly to either a converter, a by-pass valve (for Hg speciating systems), or a sample manifold. All valve and/or manifold components must be made of material that is non-reactive to the gas sampled and the calibration gas, and must be configured to safely discharge any excess gas.

**3.2.1.1.3.8 Hg Analyzer.** An instrument is required that continuously measures the total vapor phase Hg concentration in the gas stream. The analyzer may also be capable of measuring elemental and oxidized Hg separately.

**3.2.1.1.3.9 Data Recorder.** A recorder, such as a computerized data acquisition and handling system (DAHS), digital recorder, or data logger, is required for recording measurement data.

### **3.2.1.2 Reagents and Standards.**

**3.2.1.2.1 NIST Traceability.** Only NIST-certified or NIST-traceable calibration gas standards and reagents (as defined in paragraphs 3.1.4 and 3.1.5 of this appendix), and including, but not limited to, Hg gas generators and Hg gas cylinders, shall be used for the tests and procedures required under this subpart. Calibration gases with known concentrations of Hg<sup>0</sup> and HgCl<sub>2</sub> are required. Special reagents and equipment may be needed to prepare the Hg<sup>0</sup> and HgCl<sub>2</sub> gas standards (e.g., NIST-traceable solutions of HgCl<sub>2</sub> and gas generators equipped with mass flow controllers).

#### **3.2.1.2.2 Required Calibration Gas Concentrations.**

**3.2.1.2.2.1 Zero-Level Gas.** A zero-level calibration gas with a Hg concentration below the level detectable by the Hg analyzer is required for calibration error tests and cycle time tests of the CEMS.

**3.2.1.2.2.2 Low-Level Gas.** A low-level calibration gas with a Hg concentration of 20 to 30 percent of the span value is required for linearity checks and 3-level system integrity checks of the CEMS. Elemental Hg standards are required for the linearity checks and oxidized Hg standards are required for the system integrity checks.

**3.2.1.2.2.3 Mid-Level Gas.** A mid-level calibration gas with a Hg concentration of 50 to 60 percent of the span value is required for linearity checks and for 3-level system integrity checks of the CEMS, and is optional for calibration error tests and single-level system integrity checks. Elemental Hg standards are required for the linearity checks, oxidized Hg standards are required for the system integrity checks, and either elemental or oxidized Hg standards may be used for the calibration error tests.

**3.2.1.2.2.4 High-Level Gas.** A high-level calibration gas with a Hg concentration of 80 to 100 percent of the span value is required for linearity checks, 3-level system integrity checks, and cycle time tests of the CEMS, and is optional for calibration error tests and single-level system integrity checks. Elemental

Hg standards are required for the linearity checks, oxidized Hg standards are required for the system integrity checks, and either elemental or oxidized Hg standards may be used for the calibration error and cycle time tests.

**3.2.1.3 Installation and Measurement Location.** For the Hg CEMS and any additional monitoring system(s) needed to convert Hg concentrations to the desired units of measure (*i.e.*, a flow monitor, CO<sub>2</sub> or O<sub>2</sub> monitor, and/or moisture monitor, as applicable), install each monitoring system at a location: that is consistent with 63.10010(a); that represents the emissions exiting to the atmosphere; and where it is likely that the CEMS can pass the relative accuracy test.

**3.2.1.4 Monitor Span and Range Requirements.** Determine the appropriate span and range value(s) for the Hg CEMS as described in paragraphs 3.2.1.4.1 through 3.2.1.4.3 of this section.

**3.2.1.4.1 Maximum Potential Concentration.** There are three options for determining the maximum potential Hg concentration (MPC). Option 1 applies to coal combustion. You may use a default value of 10 µg/scm for all coal ranks (including coal refuse) except for lignite; for lignite, use 16 µg/scm. If different coals are blended as part of normal operation, use the highest MPC for any fuel in the blend. Option 2 is to base the MPC on the results of site-specific Hg emission testing. This option may be used only if the unit does not have add-on Hg emission controls or a flue gas desulfurization system, or if testing is performed upstream of all emission control devices. If Option 2 is selected, perform at least three test runs at the normal operating load, and the highest Hg concentration obtained in any of the tests shall be the MPC. Option 3 is to use fuel sampling and analysis to estimate the MPC. To make this estimate, use the average Hg content (*i.e.*, the weight percentage) from at least three representative fuel samples, together with other available information, including, but not limited to the maximum fuel feed rate, the heating value of the fuel, and an appropriate F-factor. Assume that all of the Hg in the fuel is emitted to the atmosphere as vapor-phase Hg.

**3.2.1.4.2 Span Value.** To determine the span value of the Hg CEMS, multiply the Hg concentration corresponding to the applicable emissions standard by two. If the result of this calculation is an exact multiple of 10 µg/scm, use the result as the span value. Otherwise, round off the result to either: the next highest integer; the next highest multiple of 5 µg/scm; or the next highest multiple of 10 µg/scm.

**3.2.1.4.3 Analyzer Range.** The Hg analyzer must be capable of reading Hg concentration as high as the MPC.

**3.2.2 Sorbent Trap Monitoring System.** A sorbent trap monitoring system (as defined in paragraph 3.1.2 of this section) may be used as an alternative to a Hg CEMS. If this option is selected, the monitoring system shall be installed, maintained, and operated in accordance with Performance Specification (PS) 12B in Appendix B to part 60 of this chapter. The system shall be certified in accordance with the provisions of section 4.1.2 of this appendix.

**3.2.3 Other Necessary Data Collection.** To convert measured hourly Hg concentrations to the units of the applicable emissions standard (*i.e.*, lb/TBtu or lb/GWh), additional data must be collected, as described in paragraphs 3.2.3.1 through 3.2.3.3 of this section. Any additional monitoring systems needed for this purpose must be certified, operated, maintained, and quality-assured according to the applicable provisions of part 75 of this chapter (see §§ 63.10010(b) through (d)). The calculation methods for the types of emission limits described in paragraphs 3.2.3.1 and 3.2.3.2 of this section are presented in section 6.2 of this appendix.

**3.2.3.1 Heat Input-Based Emission Limits.** For a heat input-based Hg emission limit (*i.e.*, in lb/TBtu), data from a certified CO<sub>2</sub> or O<sub>2</sub> monitor are needed, along with a fuel-specific F-factor and a conversion constant to convert measured Hg concentration values to the units of the standard. In some cases, the stack gas moisture content must also be considered in making these conversions.

**3.2.3.2 Electrical Output-Based Emission Rates.** If the applicable Hg limit is electrical output-based (*i.e.*, lb/GWh), hourly electrical load data and unit operating times are required in addition to hourly data from a certified stack gas flow rate monitor and (if applicable) moisture data.

3.2.3.3 **Sorbent Trap Monitoring System Operation.** Routine operation of a sorbent trap monitoring system requires the use of a certified stack gas flow rate monitor, to maintain an established ratio of stack gas flow rate to sample flow rate.

#### 4. Certification and Recertification Requirements

4.1 **Certification Requirements.** All Hg CEMS and sorbent trap monitoring systems and the additional monitoring systems used to continuously measure Hg emissions in units of the applicable emissions standard in accordance with this appendix must be certified in a timely manner, such that the initial compliance demonstration is completed no later than the applicable date in § 63.9984(f).

4.1.1 **Hg CEMS.** Table A–1, below, summarizes the certification test requirements and performance specifications for a Hg CEMS. The CEMS may not be used to report quality-assured data until these performance criteria are met. Paragraphs 4.1.1.1 through 4.1.1.5 of this section provide specific instructions for the required tests. All tests must be performed with the affected unit(s) operating (*i.e.*, combusting fuel). Except for the RATA, which must be performed at normal load, no particular load level is required for the certification tests.

4.1.1.1 **7-Day Calibration Error Test.** Perform the 7-day calibration error test on 7 consecutive source operating days, using a zero-level gas and either a high-level or a mid-level calibration gas standard (as defined in paragraphs 3.1.8, 3.1.10, and 3.1.11 of this appendix). Use a NIST-traceable elemental Hg gas standard (as defined in paragraphs 3.1.4 of this appendix) for the test. If your Hg CEMS lacks an integrated elemental Hg gas generator, you may continue to use NIST-traceable oxidized Hg gases for the 7-day calibration error test (or the daily calibration error check) until such time as NIST-traceable compressed elemental Hg gas standards, at appropriate concentration levels, are available from gas vendors. If moisture is added to the calibration gas, the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration must be accounted for in an appropriate manner. Operate the Hg CEMS in its normal sampling mode during the test. The calibrations should be approximately 24 hours apart, unless the 7-day test is performed over non-consecutive calendar days. On each day of the test, inject the zero-level and upscale gases in sequence and record the analyzer responses. Pass the calibration gas through all filters, scrubbers, conditioners, and other monitor components used during normal sampling, and through as much of the sampling probe as is practical. Do not make any manual adjustments to the monitor (*i.e.*, resetting the calibration) until after taking measurements at both the zero and upscale concentration levels. If automatic adjustments are made following both injections, conduct the calibration error test such that the magnitude of the adjustments can be determined, and use only the unadjusted analyzer responses in the calculations. Calculate the calibration error (CE) on each day of the test, as described in Table A–1 of this appendix. The CE on each day of the test must either meet the main performance specification or the alternative specification in Table A–1 of this appendix.

4.1.1.2 **Linearity Check.** Perform the linearity check using low, mid, and high-level concentrations of NIST-traceable elemental Hg standards. Three gas injections at each concentration level are required, with no two successive injections at the same concentration level. Introduce the calibration gas at the gas injection port, as specified in section 3.2.1.1.3.6 of this appendix. Operate the CEMS at its normal operating temperature and conditions. Pass the calibration gas through all filters, scrubbers, conditioners, and other components used during normal sampling, and through as much of the sampling probe as is practical. If moisture and/or chlorine is added to the calibration gas, the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration must be accounted for in an appropriate manner. Record the monitor response from the data acquisition and handling system for each gas injection. At each concentration level, use the average analyzer response to calculate the linearity error (LE), as described in Table A–1. The LE must either meet the main performance specification or the alternative specification in Table A–1.

4.1.1.3 **Three-Level System Integrity Check.** Perform the 3-level system integrity check using low, mid, and high-level calibration gas concentrations generated by a NIST-traceable source of oxidized Hg. If your Hg CEMS lacks an integrated elemental Hg gas generator, you may continue to use NIST-traceable oxidized Hg gases for the 7-day calibration error test (or the daily calibration error check) until such time as NIST-traceable compressed elemental Hg gas standards, at appropriate concentration levels, are available from gas vendors. Follow the same basic procedure as for the linearity check. If moisture and/or chlorine is added to the calibration gas, the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration must be accounted for in an appropriate manner. Calculate the system integrity error (SIE), as



described in Table A–1 of this appendix. The SIE must either meet the main performance specification or the alternative specification in Table A–1 of this appendix.

Table A–1—Required Certification Tests and Performance Specifications for H<sub>g</sub> CEMS

For this required certification test . . .	The main performance specification <sup>1</sup> is . . .	The alternate performance specification <sup>1</sup> is . . .	And the conditions of the alternate specification are . . .
7-day calibration error test <sup>2 6</sup>	$ R - A  \leq 5.0\%$ of span value, for both the zero and upscale gases, on each of the 7 days.	$ R - A  \leq 1.0 \mu\text{g}/\text{scm}$	The alternate specification may be used on any day of the test.
Linearity check <sup>3 6</sup>	$ R - A_{\text{avg}}  \leq 10.0\%$ of the reference gas concentration at each calibration gas level (low, mid, or high).	$ R - A_{\text{avg}}  \leq 0.8 \mu\text{g}/\text{scm}$	The alternate specification may be used at any gas level.
3-level system integrity check <sup>4</sup>	$ R - A_{\text{avg}}  \leq 10.0\%$ of the reference gas concentration at each calibration gas level.	$ R - A_{\text{avg}}  \leq 0.8 \mu\text{g}/\text{scm}$	The alternate specification may be used at any gas level.
RATA	20.0% RA	$ RM_{\text{avg}} - C_{\text{avg}}  +  CC  \leq 0.5 \mu\text{g}/\text{scm}^7$	$RM_{\text{avg}} < 2.5 \mu\text{g}/\text{scm}$
Cycle time test <sup>5</sup>	15 minutes where the stability criteria are readings change by $< 2.0\%$ of span or by $\leq 0.5 \mu\text{g}/\text{scm}$ , for 2 minutes.		

<sup>1</sup> Note that  $|R - A|$  is the absolute value of the difference between the reference gas value and the analyzer reading.  $|R - A_{\text{avg}}|$  is the absolute value of the difference between the reference gas concentration and the average of the analyzer responses, at a particular gas level.

<sup>2</sup> Use elemental Hg standards; a mid-level or high-level upscale gas may be used.

<sup>3</sup> Use elemental Hg standards.

<sup>4</sup> Use oxidized Hg standards.

<sup>5</sup> Use elemental Hg standards; a high-level upscale gas must be used. The cycle time test is not required for Hg CEMS that use integrated batch sampling; however, those monitoring systems must be capable of recording at least one Hg concentration reading every 15 minutes.

<sup>6</sup> If your Hg CEMS lacks an integrated elemental Hg gas generator, you may continue to use NIST-traceable oxidized Hg gases until such time as NIST-traceable compressed elemental Hg gas standards, at appropriate concentration levels, are available from gas vendors.

<sup>7</sup> Note that  $|RM_{\text{avg}} - C_{\text{avg}}|$  is the absolute difference between the mean reference method value and the mean CEMS value from the RATA; CC is the confidence coefficient from Equation 2–5 of Performance Specification 2 in appendix B to part 60 of this chapter.

4.1.1.4 **Cycle Time Test.** Perform the cycle time test, using a zero-level gas and a high-level calibration gas.

Either an elemental or oxidized NIST-traceable Hg standard may be used as the high-level gas. Perform the test in two stages—upscale and downscale. The slower of the upscale and downscale response times is the cycle time for the CEMS. Begin each stage of the test by injecting calibration gas after achieving a stable reading of the stack emissions. The cycle time is the amount of time it takes for the analyzer to register a reading that is 95 percent of the way between the stable stack emissions reading and the final, stable reading of the calibration gas concentration. Use the following criterion to determine when a stable reading

of stack emissions or calibration gas has been attained—the reading is stable if it changes by no more than 2.0 percent of the span value or 0.5 µg/scm (whichever is less restrictive) for two minutes, or a reading with a change of less than 6.0 percent from the measured average concentration over 6 minutes. Integrated batch sampling type Hg CEMS are exempted from this test; however, these systems must be capable of delivering a measured Hg concentration reading at least once every 15 minutes. If necessary to increase measurement sensitivity of a batch sampling type Hg CEMS for a specific application, you may petition the Administrator for approval of a time longer than 15 minutes between readings.

**4.1.1.5 Relative Accuracy Test Audit (RATA).** Perform the RATA of the Hg CEMS at normal load. Acceptable Hg reference methods for the RATA include ASTM D6784–16 (IBR, see § 63.14) and methods 29, 30A, and 30B in appendix A–8 to part 60 of this chapter. When method 29 or ASTM D6784–16 is used, paired sampling trains are required, and the filterable portion of the sample need not be included when making comparisons to the Hg CEMS results for purposes of a RATA. To validate a method 29 or ASTM D6784–16 test run, calculate the relative deviation (RD) using equation A–1 of this section, and assess the results as follows to validate the run. The RD must not exceed 10 percent, when the average Hg concentration is greater than 1.0 µg/dscm. If the RD specification is met, the results of the two samples shall be averaged arithmetically.

$$RD = \frac{|C_a - C_b|}{C_a + C_b} \times 100 \quad (\text{Eq. A-1})$$

Where:

RD = Relative Deviation between the Hg concentrations of samples “a” and “b” (percent),

C<sub>a</sub> = Hg concentration of Hg sample “a” (µg/dscm), and

C<sub>b</sub> = Hg concentration of Hg sample “b” (µg/dscm).

**4.1.1.5.1 Special Considerations.** A minimum of nine valid test runs must be performed, directly comparing the CEMS measurements to the reference method. More than nine test runs may be performed. If this option is chosen, the results from a maximum of three test runs may be rejected so long as the total number of test results used to determine the relative accuracy is greater than or equal to nine; however, all data must be reported including the rejected data. The minimum time per run is 21 minutes if method 30A is used. If method 29, method 30B, or ASTM D6784–16 is used, the time per run must be long enough to collect a sufficient mass of Hg to analyze. Complete the RATA within 168 unit operating hours, except when method 29 or ASTM D6784–162 is used, in which case, up to 336 operating hours may be taken to finish the test.

**4.1.1.5.2 Calculation of RATA Results.** Calculate the relative accuracy (RA) of the monitoring system, on a µg/scm basis, as described in section 12 of Performance Specification (PS) 2 in appendix B to part 60 of this chapter (see Equations 2–3 through 2–6 of PS 2). For purposes of calculating the relative accuracy, ensure that the reference method and monitoring system data are on a consistent basis, either wet or dry. The CEMS must either meet the main performance specification or the alternative specification in Table A–1 of this appendix.

**4.1.1.5.3 Bias Adjustment.** Measurement or adjustment of Hg CEMS data for bias is not required.

**4.1.2 Sorbent Trap Monitoring Systems.** For the initial certification of a sorbent trap monitoring system, only a RATA is required.

**4.1.2.1 Reference Methods.** The acceptable reference methods for the RATA of a sorbent trap monitoring system are the same as those listed in paragraph 4.1.1.5 of this section.

**4.1.2.2** “The special considerations specified in paragraph 4.1.1.5.1 of this section apply to the RATA of a sorbent trap monitoring system. During the RATA, the monitoring system must be operated and quality-

assured in accordance with Performance Specification (PS) 12B in Appendix B to part 60 of this chapter with the following exceptions for sorbent trap section 2 breakthrough:

4.1.2.2.1 For stack Hg concentrations  $>1 \mu\text{g}/\text{dscm}$ ,  $\leq 10\%$  of section 1 Hg mass;

4.1.2.2.2 For stack Hg concentrations  $\leq 1 \mu\text{g}/\text{dscm}$  and  $>0.5 \mu\text{g}/\text{dscm}$ ,  $\leq 20\%$  of section 1 Hg mass;

4.1.2.2.3 For stack Hg concentrations  $\leq 0.5 \mu\text{g}/\text{dscm}$  and  $>0.1 \mu\text{g}/\text{dscm}$ ,  $\leq 50\%$  of section 1 Hg mass; and

4.1.2.2.4 For stack Hg concentrations  $\leq 0.1 \mu\text{g}/\text{dscm}$ , no breakthrough criterion assuming all other QA/QC specifications are met.

4.1.2.3 The type of sorbent material used by the traps during the RATA must be the same as for daily operation of the monitoring system; however, the size of the traps used for the RATA may be smaller than the traps used for daily operation of the system.

4.1.2.4 **Calculation of RATA Results.** Calculate the relative accuracy (RA) of the sorbent trap monitoring system, on a  $\mu\text{g}/\text{scm}$  basis, as described in section 12 of Performance Specification (PS) 2 in appendix B to part 60 of this chapter (see Equations 2–3 through 2–6 of PS2). For purposes of calculating the relative accuracy, ensure that the reference method and monitoring system data are on a consistent moisture basis, either wet or dry. The main and alternative RATA performance specifications in Table A–1 for Hg CEMS also apply to the sorbent trap monitoring system.

4.1.2.5 **Bias Adjustment.** Measurement or adjustment of sorbent trap monitoring system data for bias is not required.

4.1.3 **Diluent Gas, Flow Rate, and/or Moisture Monitoring Systems.** Monitoring systems that are used to measure stack gas volumetric flow rate, diluent gas concentration, or stack gas moisture content, either for routine operation of a sorbent trap monitoring system or to convert Hg concentration data to units of the applicable emission limit, must be certified in accordance with the applicable provisions of part 75 of this chapter.

4.2 **Recertification.** Whenever the owner or operator makes a replacement, modification, or change to a certified CEMS or sorbent trap monitoring system that may significantly affect the ability of the system to accurately measure or record pollutant or diluent gas concentrations, stack gas flow rates, or stack gas moisture content, the owner or operator shall recertify the monitoring system. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit operation that may significantly change the concentration or flow profile, the owner or operator shall recertify the monitoring system. The same tests performed for the initial certification of the monitoring system shall be repeated for recertification, unless otherwise specified by the Administrator. Examples of changes that require recertification include: replacement of a gas analyzer; complete monitoring system replacement, and changing the location or orientation of the sampling probe.

## 5. Ongoing Quality Assurance (QA) and Data Validation

### 5.1 Hg CEMS.

5.1.1 **Required QA Tests.** Periodic QA testing of each Hg CEMS is required following initial certification. The required QA tests, the test frequencies, and the performance specifications that must be met are summarized in Table A–2, below. All tests must be performed with the affected unit(s) operating (*i.e.*, combusting fuel), however, the daily calibration may optionally be performed off-line. The RATA must be performed at normal load, but no particular load level is required for the other tests. For each test, follow the same basic procedures in section 4.1.1 of this appendix that were used for initial certification.

5.1.2 **Test Frequency.** The frequency for the required QA tests of the Hg CEMS shall be as follows:

5.1.2.1 Calibration error tests of the Hg CEMS are required daily, except during unit outages. Use a NIST-traceable elemental Hg gas standard for these calibrations. If your Hg CEMS lacks an integrated elemental Hg gas generator, you may continue to use NIST-traceable oxidized Hg gases for the 7-day calibration error test (or the daily calibration error check) until such time as NIST-traceable compressed elemental Hg gas standards, at appropriate concentration levels, are available from gas vendors. Both a zero-level gas and either a mid-level or high-level gas are required for these calibrations.

5.1.2.2 Perform a linearity check of the Hg CEMS in each QA operating quarter, using low-level, mid-level, and high-level NIST-traceable elemental Hg standards. For units that operate infrequently, limited exemptions from this test are allowed for “non-QA operating quarters”. A maximum of three consecutive exemptions for this reason are permitted, following the quarter of the last test. After the third consecutive exemption, a linearity check must be performed in the next calendar quarter or within a grace period of 168 unit or stack operating hours after the end of that quarter. The test frequency for 3-level system integrity checks (if performed in lieu of linearity checks) is the same as for the linearity checks. Use low-level, mid-level, and high-level NIST-traceable oxidized Hg standards for the system integrity checks.

5.1.2.3 Perform a single-level system integrity check weekly, *i.e.*, once every 7 operating days (see the third column in Table A–2 of this appendix).

5.1.2.4 The test frequency for the RATAs of the Hg CEMS shall be annual, *i.e.*, once every four QA operating quarters. For units that operate infrequently, extensions of RATA deadlines are allowed for non-QA operating quarters. Following a RATA, if there is a subsequent non-QA quarter, it extends the deadline for the next test by one calendar quarter. However, there is a limit to these extensions; the deadline may not be extended beyond the end of the eighth calendar quarter after the quarter of the last test. At that point, a RATA must either be performed within the eighth calendar quarter or in a 720 hour unit or stack operating hour grace period following that quarter. When a required annual RATA is done within a grace period, the deadline for the next RATA is three QA operating quarters after the quarter in which the grace period test is performed.

5.1.3 **Grace Periods.**

5.1.3.1 A 168 unit or stack operating hour grace period is available for quarterly linearity checks and 3-level system integrity checks of the Hg CEMS.

5.1.3.2 A 720 unit or stack operating hour grace period is available for RATAs of the Hg CEMS.

5.1.3.3 There is no grace period for weekly system integrity checks. The test must be completed once every 7 operating days.

5.1.4 **Data Validation.** The Hg CEMS is considered to be out-of-control, and data from the CEMS may not be reported as quality-assured, when any one of the acceptance criteria for the required QA tests in Table A–2 is not met. The CEMS is also considered to be out-of-control when a required QA test is not performed on schedule or within an allotted grace period. To end an out-of-control period, the QA test that was either failed or not done on time must be performed and passed. Out-of-control periods are counted as hours of monitoring system downtime.

5.1.5 **Conditional Data Validation.** For certification, recertification, and diagnostic testing of Hg monitoring systems, and for the required QA tests when non-redundant backup Hg monitoring systems or temporary like-kind Hg analyzers are brought into service, the conditional data validation provisions in §§ 75.20(b)(3)(ii) through (b)(3)(ix) of this chapter may be used to avoid or minimize data loss. The allotted window of time to complete 7-day calibration error tests, linearity checks, cycle time tests, and RATAs shall be as specified in § 75.20(b)(3)(iv) of this chapter. Required system integrity checks must be completed within 168 unit or stack operating hours after the probationary calibration error test.

Table A–2—On-Going QA Test Requirements for H<sub>g</sub> CEMS

Perform this type of QA test . . .	At this frequency . . .	With these qualifications and exceptions . . .	Acceptance criteria . . .
Calibration error test <sup>5</sup>	Daily	<ul style="list-style-type: none"> <li>• Use either a mid- or high-level gas</li> <li>• Use elemental Hg</li> <li>• Calibrations are not required when the unit is not in operation.</li> </ul>	$ R - A  \leq 5.0\%$ of span value <i>or</i> $ R - A  \leq 1.0 \mu\text{g}/\text{scm}$ .
Single-level system integrity check	Weekly <sup>1</sup>	<ul style="list-style-type: none"> <li>• Use oxidized Hg—either mid- or high-level</li> </ul>	$ R - A_{\text{avg}}  \leq 10.0\%$ of the reference gas value <i>or</i> $ R - A_{\text{avg}}  \leq 0.8 \mu\text{g}/\text{scm}$ .
Linearity check <i>or</i> 3-level system integrity check	Quarterly <sup>3</sup>	<ul style="list-style-type: none"> <li>• Required in each “QA operating quarter”<sup>2</sup> and no less than once every 4 calendar quarters</li> <li>• 168 operating hour grace period available</li> <li>• Use elemental Hg for linearity check</li> <li>• Use oxidized Hg for system integrity check</li> </ul>	$ R - A_{\text{avg}}  \leq 10.0\%$ of the reference gas value, at each calibration gas level <i>or</i> $ R - A_{\text{avg}}  \leq 0.8 \mu\text{g}/\text{scm}$ .
RATA	Annual <sup>4</sup>	<ul style="list-style-type: none"> <li>• Test deadline may be extended for “non-QA operating quarters,” up to a maximum of 8 quarters from the quarter of the previous test</li> <li>• 720 operating hour grace period available</li> </ul>	$\leq 20.0\%$ RA <i>or</i> $ RM_{\text{avg}} - C_{\text{avg}}  +  CC  \leq 0.5 \mu\text{g}/\text{scm}$ , if $RM_{\text{avg}} < 2.5 \mu\text{g}/\text{scm}$ .

<sup>1</sup> “Weekly” means once every 7 operating days.

<sup>2</sup> A “QA operating quarter” is a calendar quarter with at least 168 unit or stack operating hours.

<sup>3</sup> “Quarterly” means once every QA operating quarter.

<sup>4</sup> “Annual” means once every four QA operating quarters.

<sup>5</sup> If your Hg CEMS lacks an integrated elemental Hg gas generator, you may continue to use NIST-traceable oxidized Hg gases until such time as NIST-traceable compressed elemental Hg gas standards, at appropriate concentration levels, are available from gas vendors.

5.1.6 **Adjustment of Span.** If you discover that a span adjustment is needed (e.g., if the Hg concentration readings exceed the span value for a significant percentage of the unit operating hours in a calendar quarter), you must implement the span adjustment within 90 days after the end of the calendar quarter in which you identify the need for the adjustment. A diagnostic linearity check is required within 168 unit or stack operating hours after changing the span value.

## 5.2 Sorbent Trap Monitoring Systems.

5.2.1 Each sorbent trap monitoring system shall be continuously operated and maintained in accordance with Performance Specification (PS) 12B in appendix B to part 60 of this chapter. The QA/QC criteria for routine operation of the system are summarized in Table 12B–1 of PS 12B. Each pair of sorbent traps may be used to sample the stack gas for up to 15 operating days.

5.2.2 For ongoing QA, periodic RATAs of the system are required.

5.2.2.1 The RATA frequency shall be annual, *i.e.*, once every four QA operating quarters. The provisions in section 5.1.2.4 of this appendix pertaining to RATA deadline extensions also apply to sorbent trap monitoring systems.

5.2.2.2 The same RATA performance criteria specified in Table A–2 for Hg CEMS also apply to the annual RATAs of the sorbent trap monitoring system.

5.2.2.3 A 720 unit or stack operating hour grace period is available for RATAs of the monitoring system.

5.2.3 Data validation for sorbent trap monitoring systems shall be done in accordance with Table 12B–1 in Performance Specification (PS) 12B in appendix B to part 60 of this chapter. All periods of invalid data shall be counted as hours of monitoring system downtime.

**5.3 Flow Rate, Diluent Gas, and Moisture Monitoring Systems.** The on-going QA test requirements for these monitoring systems are specified in part 75 of this chapter (see §§ 63.10010(b) through (d)).

**5.4 QA/QC Program Requirements.** The owner or operator shall develop and implement a quality assurance/quality control (QA/QC) program for the Hg CEMS and/or sorbent trap monitoring systems that are used to provide data under this subpart. At a minimum, the program shall include a written plan that describes in detail (or that refers to separate documents containing) complete, step-by-step procedures and operations for the most important QA/QC activities. Electronic storage of the QA/QC plan is permissible, provided that the information can be made available in hard copy to auditors and inspectors. The QA/QC program requirements for the diluent gas, flow rate, and moisture monitoring systems described in section 3.2.1.3 of this appendix are specified in section 1 of appendix B to part 75 of this chapter.

#### **5.4.1 General Requirements.**

**5.4.1.1 Preventive Maintenance.** Keep a written record of procedures needed to maintain the Hg CEMS and/or sorbent trap monitoring system(s) in proper operating condition and a schedule for those procedures. Include, at a minimum, all procedures specified by the manufacturers of the equipment and, if applicable, additional or alternate procedures developed for the equipment.

**5.4.1.2 Recordkeeping and Reporting.** Keep a written record describing procedures that will be used to implement the recordkeeping and reporting requirements of this appendix.

**5.4.1.3 Maintenance Records.** Keep a record of all testing, maintenance, or repair activities performed on any Hg CEMS or sorbent trap monitoring system in a location and format suitable for inspection. A maintenance log may be used for this purpose. The following records should be maintained: date, time, and description of any testing, adjustment, repair, replacement, or preventive maintenance action performed on any monitoring system and records of any corrective actions associated with a monitor outage period. Additionally, any adjustment that may significantly affect a system's ability to accurately measure emissions data must be recorded (e.g., changing the dilution ratio of a CEMS), and a written explanation of the procedures used to make the adjustment(s) shall be kept.

#### **5.4.2 Specific Requirements for Hg CEMS.**

**5.4.2.1 Daily Calibrations, Linearity Checks and System Integrity Checks.** Keep a written record of the procedures used for daily calibrations of the Hg CEMS. If moisture and/or chlorine is added to the Hg calibration gas, document how the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration is accounted for in an appropriate manner. Also keep records of the procedures used to perform linearity checks of the Hg CEMS and the procedures for system integrity checks of the Hg CEMS. Document how the test results are calculated and evaluated.

**5.4.2.2 Monitoring System Adjustments.** Document how each component of the Hg CEMS will be adjusted to provide correct responses to calibration gases after routine maintenance, repairs, or corrective actions.

**5.4.2.3 Relative Accuracy Test Audits.** Keep a written record of procedures used for RATAs of the Hg CEMS. Indicate the reference methods used and document how the test results are calculated and evaluated.

#### 5.4.3 **Specific Requirements for Sorbent Trap Monitoring Systems.**

5.4.3.1 **Sorbent Trap Identification and Tracking.** Include procedures for inscribing or otherwise permanently marking a unique identification number on each sorbent trap, for chain of custody purposes. Keep records of the ID of the monitoring system in which each sorbent trap is used, and the dates and hours of each Hg collection period.

5.4.3.2 **Monitoring System Integrity and Data Quality.** Document the procedures used to perform the leak checks when a sorbent trap is placed in service and removed from service. Also Document the other QA procedures used to ensure system integrity and data quality, including, but not limited to, gas flow meter calibrations, verification of moisture removal, and ensuring air-tight pump operation. In addition, the QA plan must include the data acceptance and quality control criteria in Table 12B–1 in section 9.0 of Performance Specification (PS) 12B in Appendix B to part 60 of this chapter. All reference meters used to calibrate the gas flow meters (e.g., wet test meters) shall be periodically recalibrated. Annual, or more frequent, recalibration is recommended. If a NIST-traceable calibration device is used as a reference flow meter, the QA plan must include a protocol for ongoing maintenance and periodic recalibration to maintain the accuracy and NIST-traceability of the calibrator.

5.4.3.3 **Hg Analysis.** Explain the chain of custody employed in packing, transporting, and analyzing the sorbent traps. Keep records of all Hg analyses. The analyses shall be performed in accordance with the procedures described in section 11.0 of Performance Specification (PS) 12B in Appendix B to part 60 of this chapter.

5.4.3.4 **Data Collection Period.** State, and provide the rationale for, the minimum acceptable data collection period (e.g., one day, one week, etc.) for the size of sorbent trap selected for the monitoring. Address such factors as the Hg concentration in the stack gas, the capacity of the sorbent trap, and the minimum mass of Hg required for the analysis. Each pair of sorbent traps may be used to sample the stack gas for up to 14 operating days.

5.4.3.5 **Relative Accuracy Test Audit Procedures.** Keep records of the procedures and details peculiar to the sorbent trap monitoring systems that are to be followed for relative accuracy test audits, such as sampling and analysis methods.

### 6. Data Reduction and Calculations

#### 6.1 Data Reduction.

6.1.1 Reduce the data from Hg CEMS to hourly averages, in accordance with § 60.13(h)(2) of this chapter.

6.1.2 For sorbent trap monitoring systems, determine the Hg concentration for each data collection period and assign this concentration value to each operating hour in the data collection period.

6.1.3 For any operating hour in which valid data are not obtained, either for Hg concentration or for a parameter used in the emissions calculations (*i.e.*, flow rate, diluent gas concentration, or moisture, as applicable), do not calculate the Hg emission rate for that hour. For the purposes of this appendix, part 75 substitute data values are not considered to be valid data.

6.1.4 Operating hours in which valid data are not obtained for Hg concentration are considered to be hours of monitor downtime. The use of substitute data for Hg concentration is not required.

6.2 **Calculation of Hg Emission Rates.** Use the applicable calculation methods in paragraphs 6.2.1 and 6.2.2 of this section to convert Hg concentration values to the appropriate units of the emission standard.

6.2.1 **Heat Input-Based Hg Emission Rates.** Calculate hourly heat input-based Hg emission rates, in units of lb/TBtu, according to sections 6.2.1.1 through 6.2.1.4 of this appendix.

6.2.1.1 Select an appropriate emission rate equation from among Equations 19–1 through 19–9 in EPA Method 19 in appendix A–7 to part 60 of this chapter.

6.2.1.2 Calculate the Hg emission rate in lb/MMBtu, using the equation selected from Method 19. Multiply the Hg concentration value by  $6.24 \times 10^{-11}$  to convert it from  $\mu\text{g}/\text{scm}$  to lb/scf. In cases where an appropriate F-factor is not listed in Table 19–2 of Method 19, you may use F-factors from Table 1 in section 3.3.5 of appendix F to part 75 of this chapter, or F-factors derived using the procedures in section 3.3.6 of appendix F to part 75 of this chapter. Also, for startup and shutdown hours, you may calculate the Hg emission rate using the applicable diluent cap value specified in section 3.3.4.1 of appendix F to part 75 of this chapter, provided that the diluent gas monitor is not out-of-control and the hourly average  $\text{O}_2$  concentration is above 14.0%  $\text{O}_2$  (19.0% for an IGCC) or the hourly average  $\text{CO}_2$  concentration is below 5.0%  $\text{CO}_2$  (1.0% for an IGCC), as applicable.

6.2.1.3 Multiply the lb/MMBtu value obtained in section 6.2.1.2 of this appendix by  $10^6$  to convert it to lb/TBtu.

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

6.2.2 **Electrical Output-Based Hg Emission Rates.** Calculate electrical output-based Hg emission limits in units of lb/GWh, according to sections 6.2.2.1 through 6.2.2.3 of this appendix.

6.2.2.1 Calculate the Hg mass emissions for each operating hour in which valid data are obtained for all parameters, using Equation A–2 of this section (for wet-basis measurements of Hg concentration) or Equation A–3 of this section (for dry-basis measurements), as applicable:

$$M_h = K C_h Q_h \quad (\text{Equation A-2})$$

Where:

$M_h$  = Hg mass emission rate for the hour (lb/h)

$K$  = Units conversion constant,  $6.24 \times 10^{-11}$  lb-scm/ $\mu\text{g}$ -scf,

$C_h$  = Hourly average Hg concentration, wet basis ( $\mu\text{g}/\text{scm}$ )

$Q_h$  = Stack gas volumetric flow rate for the hour (scfh).

(Note: Use unadjusted flow rate values; bias adjustment is not required)

$$M_h = K C_h Q_h (1 - B_{ws}) \quad (\text{Equation A-3})$$

Where:

$M_h$  = Hg mass emission rate for the hour (lb/h)

$K$  = Units conversion constant,  $6.24 \times 10^{-11}$  lb-scm/ $\mu\text{g}$ -scf.

$C_h$  = Hourly average Hg concentration, dry basis ( $\mu\text{g}/\text{dscm}$ ).



$Q_h$  = Stack gas volumetric flow rate for the hour (scfh)

(Note: Use unadjusted flow rate values; bias adjustment is not required).

$B_{ws}$  = Moisture fraction of the stack gas, expressed as a decimal (equal to % H<sub>2</sub>O/100)

6.2.2.2 Use Equation A-4 of this section to calculate the emission rate for each unit or stack operating hour in which valid data are obtained for all parameters.

$$E_{ho} = \frac{M_h}{(MW)_h} \times 10^3 \quad (\text{Equation A-4})$$

Where:

$E_{ho}$  = Electrical output-based Hg emission rate (lb/GWh).

$M_h$  = Hg mass emission rate for the hour, from Equation A-2 or A-3 of this section, as applicable (lb/h).

$(MW)_h$  = Gross electrical load for the hour, in megawatts (MW).

$10^3$  = Conversion factor from megawatts to gigawatts.

6.2.2.3 The applicable gross output-based Hg emission rate limit in Table 1 or 2 to this subpart must be met on a 30- (or 90-) boiler operating day rolling average basis, except as otherwise provided in § 63.10009(a)(2). Use Equation A-5 of this appendix to calculate the Hg emission rate for each averaging period.

$$\bar{E}_o = \frac{\sum_{h=1}^n E_{ho}}{n} \quad (\text{Eq. A-5})$$

Where:

$E_o$  = Hg emission rate for the averaging period (lb/GWh),

$E_{ho}$  = Gross output-based hourly Hg emission rate for unit or stack sampling hour "h" in the averaging period, from Equation A-4 of this appendix (lb/GWh), and

n = Number of unit or stack operating hours in the averaging period in which valid data were obtained for all parameters. (Note: Do *not* include non-operating hours with zero emission rates in the average).

## 7. Recordkeeping and Reporting

**7.1 Recordkeeping Provisions.** For the Hg CEMS and/or sorbent trap monitoring systems and any other necessary monitoring systems installed at each affected unit, the owner or operator must maintain a file of all measurements, data, reports, and other information required by this appendix in a form suitable for inspection, for 5 years from the date of each record, in accordance with § 63.10033. The file shall contain the information in paragraphs 7.1.1 through 7.1.10 of this section.

**7.1.1 Monitoring Plan Records.** For each affected unit or group of units monitored at a common stack, the owner or operator shall prepare and maintain a monitoring plan for the Hg CEMS and/or sorbent trap

monitoring system(s) and any other monitoring system(s) (*i.e.*, flow rate, diluent gas, or moisture systems) needed for routine operation of a sorbent trap monitoring system or to convert Hg concentrations to units of the applicable emission standard. The monitoring plan shall contain essential information on the continuous monitoring systems and shall Document how the data derived from these systems ensure that all Hg emissions from the unit or stack are monitored and reported.

7.1.1.1 **Updates.** Whenever the owner or operator makes a replacement, modification, or change in a certified continuous monitoring system that is used to provide data under this subpart (including a change in the automated data acquisition and handling system or the flue gas handling system) which affects information reported in the monitoring plan (e.g., a change to a serial number for a component of a monitoring system), the owner or operator shall update the monitoring plan.

7.1.1.2 **Contents of the Monitoring Plan.** For Hg CEMS and sorbent trap monitoring systems, the monitoring plan shall contain the information in sections 7.1.1.2.1 and 7.1.1.2.2 of this appendix, as applicable. For stack gas flow rate, diluent gas, and moisture monitoring systems, the monitoring plan shall include the information required for those systems under § 75.53 (g) of this chapter.

7.1.1.2.1 **Electronic.** The electronic monitoring plan records must include the following: unit or stack ID number(s); monitoring location(s); the Hg monitoring methodologies used; emissions controls; Hg monitoring system information, including, but not limited to: Unique system and component ID numbers; the make, model, and serial number of the monitoring equipment; the sample acquisition method; formulas used to calculate Hg emissions; and Hg monitor span and range information. The electronic monitoring plan shall be evaluated and submitted using the ECMPS Client Tool provided by the Clean Air Markets Division in the Office of Atmospheric Programs of the EPA.

7.1.1.2.2 **Hard Copy.** Keep records of the following: schematics and/or blueprints showing the location of the Hg monitoring system(s) and test ports; data flow diagrams; test protocols; monitor span and range calculations; miscellaneous technical justifications.

7.1.2 **Operating Parameter Records.** The owner or operator shall record the following information for each operating hour of each affected unit and also for each group of units utilizing a common stack, to the extent that these data are needed to convert Hg concentration data to the units of the emission standard. For non-operating hours, record only the items in paragraphs 7.1.2.1 and 7.1.2.2 of this section. If there is heat input to the unit(s), but no electrical load, record only the items in paragraphs 7.1.2.1, 7.1.2.2, and (if applicable) 7.1.2.4 of this section.

7.1.2.1 The date and hour;

7.1.2.2 The unit or stack operating time (rounded up to the nearest fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator);

7.1.2.3 The hourly gross unit load (rounded to nearest MWe); and

7.1.2.4 If applicable, the F-factor used to calculate the heat input-based Hg emission rate.

7.1.2.5 If applicable, a flag to indicate that the hour is a startup or shutdown hour (as defined in § 63.10042).

7.1.2.6 The EGUs that constitute an emissions averaging group.

7.1.3 **Hg Emissions Records (Hg CEMS).** For each affected unit or common stack using a Hg CEMS, the owner or operator shall record the following information for each unit or stack operating hour:

7.1.3.1 The date and hour;

7.1.3.2 Monitoring system and component identification codes, as provided in the monitoring plan, if the CEMS provides a quality-assured value of Hg concentration for the hour;

7.1.3.3 The hourly Hg concentration, if a quality-assured value is obtained for the hour ( $\mu\text{g}/\text{scm}$ , with one leading non-zero digit and one decimal place, expressed in scientific notation). Use the following rounding convention: If the digit immediately following the first decimal place is 5 or greater, round the first decimal place upward (increase it by one); if the digit immediately following the first decimal place is 4 or less, leave the first decimal place unchanged;

7.1.3.4 A special code, indicating whether or not a quality-assured Hg concentration is obtained for the hour. This code may be entered manually when a temporary like-kind replacement Hg analyzer is used for reporting; and

7.1.3.5 Monitor data availability, as a percentage of unit or stack operating hours, calculated according to § 75.32 of this chapter.

**7.1.4 Hg Emissions Records (Sorbent Trap Monitoring Systems).** For each affected unit or common stack using a sorbent trap monitoring system, each owner or operator shall record the following information for the unit or stack operating hour in each data collection period:

7.1.4.1 The date and hour;

7.1.4.2 Monitoring system and component identification codes, as provided in the monitoring plan, if the sorbent trap system provides a quality-assured value of Hg concentration for the hour;

7.1.4.3 The hourly Hg concentration, if a quality-assured value is obtained for the hour ( $\mu\text{g}/\text{scm}$ , with one leading non-zero digit and one decimal place, expressed in scientific notation). Use the following rounding convention: If the digit immediately following the first decimal place is 5 or greater, round the first decimal place upward (increase it by one); if the digit immediately following the first decimal place is 4 or less, leave the first decimal place unchanged. Note that when a single quality-assured Hg concentration value is obtained for a particular data collection period, that single concentration value is applied to each operating hour of the data collection period.

7.1.4.4 A special code, indicating whether or not a quality-assured Hg concentration is obtained for the hour;

7.1.4.5 The average flow rate of stack gas through each sorbent trap (in appropriate units, e.g., liters/min, cc/min, dscm/min);

7.1.4.6 The gas flow meter reading (in dscm, rounded to the nearest hundredth), at the beginning and end of the collection period and at least once in each unit operating hour during the collection period;

7.1.4.7 The ratio of the stack gas flow rate to the sample flow rate, as described in section 12.2 of Performance Specification (PS) 12B in Appendix B to part 60 of this chapter; and

7.1.4.8 Monitor data availability, as a percentage of unit or stack operating hours, calculated according to § 75.32 of this chapter.

**7.1.5 Stack Gas Volumetric Flow Rate Records.**

7.1.5.1 Hourly measurements of stack gas volumetric flow rate during unit operation are required for routine operation of sorbent trap monitoring systems, to maintain the required ratio of stack gas flow rate to sample flow rate (see section 8.2.2 of Performance Specification (PS) 12B in Appendix B to part 60 of this chapter). Hourly stack gas flow rate data are also needed in order to demonstrate compliance with electrical output-based Hg emissions limits, as provided in section 6.2.2 of this appendix.

7.1.5.2 For each affected unit or common stack, if hourly measurements of stack gas flow rate are needed for sorbent trap monitoring system operation or to convert Hg concentrations to the units of the emission standard, use a flow rate monitor that meets the requirements of part 75 of this chapter to record the required data. You must keep hourly flow rate records, as specified in § 75.57(c)(2) of this chapter.

#### **7.1.6 Records of Stack Gas Moisture Content.**

7.1.6.1 Correction of hourly Hg concentration data for moisture is sometimes required when converting Hg concentrations to the units of the applicable Hg emissions limit. In particular, these corrections are required:

7.1.6.1.1 For sorbent trap monitoring systems;

7.1.6.1.2 For Hg CEMS that measure Hg concentration on a dry basis, when you must calculate electrical output-based Hg emission rates; and

7.1.6.1.3 When using certain equations from EPA Method 19 in appendix A-7 to part 60 of this chapter to calculate heat input-based Hg emission rates.

7.1.6.2 If hourly moisture corrections are required, either use a fuel-specific default moisture percentage from § 75.11(b)(1) of this chapter or a certified moisture monitoring system that meets the requirements of part 75 of this chapter, to record the required data. If you use a moisture monitoring system, you must keep hourly records of the stack gas moisture content, as specified in § 75.57(c)(3) of this chapter.

#### **7.1.7 Records of Diluent Gas (CO<sub>2</sub> or O<sub>2</sub>) Concentration.**

7.1.7.1 When a heat input-based Hg mass emissions limit must be met, in units of lb/TBtu, hourly measurements of CO<sub>2</sub> or O<sub>2</sub> concentration are required to convert Hg concentrations to units of the standard.

7.1.7.2 If hourly measurements of diluent gas concentration are needed, use a certified CO<sub>2</sub> or O<sub>2</sub> monitor that meets the requirements of part 75 of this chapter to record the required data. You must keep hourly CO<sub>2</sub> or O<sub>2</sub> concentration records, as specified in § 75.57(g) of this chapter.

**7.1.8 Hg Emission Rate Records.** For applicable Hg emission limits in units of lb/TBtu or lb/GWh, record the following information for each affected unit or common stack:

7.1.8.1 The date and hour;

7.1.8.2 The hourly Hg emissions rate (lb/TBtu or lb/GWh, as applicable), calculated according to section 6.2.1 or 6.2.2 of this appendix, rounded to the same precision as the standard (*i.e.*, with one leading non-zero digit and one decimal place, expressed in scientific notation), if valid values of Hg concentration and all other required parameters (stack gas volumetric flow rate, diluent gas concentration, electrical load, and moisture data, as applicable) are obtained for the hour. Use the following rounding convention: If the digit immediately following the first decimal place is 5 or greater, round the first decimal place upward (increase it by one); if the digit immediately following the first decimal place is 4 or less, leave the first decimal place unchanged;

7.1.8.3 An identification code for the formula (either the selected equation from Method 19 in section 6.2.1 of this appendix or Equation A-4 in section 6.2.2 of this appendix) used to derive the hourly Hg emission rate from Hg concentration, flow rate, electrical load, diluent gas concentration, and moisture data (as applicable); and

7.1.8.4 A code indicating that the Hg emission rate was not calculated for the hour, if valid data for Hg concentration and/or any of the other necessary parameters are not obtained for the hour. For the purposes of this appendix, the substitute data values required under part 75 of this chapter for diluent gas concentration, stack gas flow rate and moisture content are not considered to be valid data.

7.1.8.5 If applicable, a code to indicate that the default gross output (as defined in § 63.10042) was used to calculate the Hg emission rate.

7.1.8.6 If applicable, a code to indicate that the diluent cap (as defined in § 63.10042) was used to calculate the Hg emission rate.

**7.1.9 Certification and Quality Assurance Test Records.** For any Hg CEMS and sorbent trap monitoring systems used to provide data under this subpart, record the following certification and quality-assurance information:

7.1.9.1 The reference values, monitor responses, and calculated calibration error (CE) values, and a flag to indicate whether the test was done using elemental or oxidized Hg, for all required 7-day calibration error tests and daily calibration error tests of the Hg CEMS;

7.1.9.2 The reference values, monitor responses, and calculated linearity error (LE) or system integrity error (SIE) values for all linearity checks of the Hg CEMS, and for all single-level and 3-level system integrity checks of the Hg CEMS;

7.1.9.3 The CEMS and reference method readings for each test run and the calculated relative accuracy results for all RATAs of the Hg CEMS and/or sorbent trap monitoring systems;

7.1.9.4 The stable stack gas and calibration gas readings and the calculated results for the upscale and downscale stages of all required cycle time tests of the Hg CEMS or, for a batch sampling Hg CEMS, the interval between measured Hg concentration readings;

7.1.9.5 Supporting information for all required RATAs of the Hg monitoring systems, including records of the test dates, the raw reference method and monitoring system data, the results of sample analyses to substantiate the reported test results, and records of sampling equipment calibrations;

7.1.9.6 For sorbent trap monitoring systems, also keep records of the results of all analyses of the sorbent traps used for routine daily operation of the system, and information documenting the results of all leak checks and the other applicable quality control procedures described in Table 12B-1 of Performance Specification (PS) 12B in appendix B to part 60 of this chapter.

7.1.9.7 For stack gas flow rate, diluent gas, and (if applicable) moisture monitoring systems, you must keep records of all certification, recertification, diagnostic, and on-going quality-assurance tests of these systems, as specified in § 75.59 of this chapter.

## **7.2 Reporting Requirements.**

**7.2.1 General Reporting Provisions.** The owner or operator shall comply with the following requirements for reporting Hg emissions from each affected unit (or group of units monitored at a common stack) under this subpart:

7.2.1.1 Notifications, in accordance with paragraph 7.2.2 of this section;

7.2.1.2 Monitoring plan reporting, in accordance with paragraph 7.2.3 of this section;

7.2.1.3 Certification, recertification, and QA test submittals, in accordance with paragraph 7.2.4 of this section; and

7.2.1.4 Electronic quarterly report submittals, in accordance with paragraph 7.2.5 of this section.

**7.2.2 Notifications.** The owner or operator shall provide notifications for each affected unit (or group of units monitored at a common stack) under this subpart in accordance with § 63.10030.

**7.2.3 Monitoring Plan Reporting.** For each affected unit (or group of units monitored at a common stack) under this subpart using Hg CEMS or sorbent trap monitoring system to measure Hg emissions, the owner or operator shall make electronic and hard copy monitoring plan submittals as follows:

7.2.3.1 For an EGU that begins reporting hourly Hg concentrations with a previously-certified Hg monitoring system, submit the monitoring plan information in section 7.1.1.2 of this appendix prior to or concurrent with

the first required quarterly emissions report. For a new EGU, or for an EGU switching to continuous monitoring of Hg emissions after having implemented another allowable compliance option under this subpart, submit the information in section 7.1.1.2 of this appendix at least 21 days prior to the start of initial certification testing of the CEMS. Also submit the monitoring plan information in section 75.53(g) pertaining to any required flow rate, diluent gas, and moisture monitoring systems within the applicable time frame specified in this section, if the required records are not already in place.

7.2.3.2 Whenever an update of the monitoring plan is required, as provided in paragraph 7.1.1.1 of this section. An electronic monitoring plan information update must be submitted either prior to or concurrent with the quarterly report for the calendar quarter in which the update is required.

7.2.3.3 All electronic monitoring plan submittals and updates shall be made to the Administrator using the ECMPS Client Tool. Hard copy portions of the monitoring plan shall be kept on record according to section 7.1 of this appendix.

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

#### **7.2.5 Quarterly Reports.**

7.2.5.1 Beginning with the report for the calendar quarter in which the initial compliance demonstration is completed or the calendar quarter containing the applicable date in § 63.9984, the owner or operator of any affected unit shall use the ECMPS Client Tool to submit electronic quarterly reports to the Administrator, in an XML format specified by the Administrator, for each affected unit (or group of units monitored at a common stack) under this subpart.

7.2.5.2 The electronic reports must be submitted within 30 days following the end of each calendar quarter, except for units that have been placed in long-term cold storage.

7.2.5.3 Each electronic quarterly report shall include the following information:

7.2.5.3.1 The date of report generation;

7.2.5.3.2 Facility identification information;

7.2.5.3.3 The information in paragraphs 7.1.2 through 7.1.8 of this section, as applicable to the Hg emission measurement methodology (or methodologies) used and the units of the Hg emission standard(s); and

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

**7.2.5.4 Compliance Certification.** Based on reasonable inquiry of those persons with primary responsibility for ensuring that all Hg emissions from the affected unit(s) under this subpart have been correctly and fully monitored, the owner or operator shall submit a compliance certification in support of each electronic quarterly emissions monitoring report. The compliance certification shall include a statement by a responsible official with that official's name, title, and signature, certifying that, to the best of his or her knowledge, the report is true, accurate, and complete.

## Appendix B to Subpart UUUUU of Part 63—HCl and HF Monitoring Provisions

### 1. Applicability

These monitoring provisions apply to the measurement of HCl and/or HF emissions from electric utility steam generating units, using CEMS. The CEMS must be capable of measuring HCl and/or HF in the appropriate units of the applicable emissions standard (e.g., lb/MMBtu, lb/MWh, or lb/GWh).

### 2. Monitoring of HCl and/or HF Emissions

**2.1 Monitoring System Installation Requirements.** Install HCl and/or HF CEMS and any additional monitoring systems needed to convert pollutant concentrations to units of the applicable emissions limit in accordance with § 63.10010(a) and either Performance Specification 15 (PS 15) of appendix B to part 60 of this chapter for extractive Fourier Transform Infrared Spectroscopy (FTIR) continuous emissions monitoring systems or Performance Specification 18 (PS 18) of appendix B to part 60 of this chapter for HCl CEMS.

**2.2 Primary and Backup Monitoring Systems.** The provisions pertaining to primary and redundant backup monitoring systems in section 2.2 of appendix A to this subpart apply to HCl and HF CEMS and any additional monitoring systems needed to convert pollutant concentrations to units of the applicable emissions limit.

#### **2.3 Monitoring System Equipment, Supplies, Definitions, and General Operation.**

The following provisions apply:

2.3.1 PS 15, Sections 2.0, 3.0, 4.0, 5.0, 6.0, and 10.0 of appendix B to part 60 of this chapter; or

2.3.2 PS 18, Sections 3.0, 6.0, and 11.0 of appendix B to part 60 of this chapter.

### 3. Initial Certification Procedures

The initial certification procedures for the HCl or HF CEMS used to provide data under this subpart are as follows:

3.1 If you choose to follow PS 15 of appendix B to part 60 of this chapter, then your HCl and/or HF CEMS must be certified according to PS 15 using the procedures for gas auditing and comparison to a reference method (RM) as specified in sections 3.1.1 and 3.1.2 below.

3.1.1 You must conduct a gas audit of the HCl and/or HF CEMS as described in section 9.1 of Performance Specification 15, with the exceptions listed in sections 3.1.2.1 and 3.1.2.2 below.

3.1.1.1 The audit sample gas does not have to be obtained from the Administrator; however, it must be (1) from a secondary source of certified gases (*i.e.*, independent of any calibration gas used for the daily calibration assessments) and (2) directly traceable to National Institute of Standards and Technology (NIST) or VSL Dutch Metrology Institute (VSL) reference materials through an unbroken chain of comparisons. If audit gas traceable to NIST or VSL reference materials is not available, you may use a gas with a concentration certified to a specified uncertainty by the gas manufacturer.

3.1.1.2 Analyze the results of the gas audit using the calculations in section 12.1 of Performance Specification 15. The calculated correction factor (CF) from Eq. 6 of Performance Specification 15 must be between 0.85 and 1.15. You do not have to test the bias for statistical significance.

3.1.2 You must perform a relative accuracy test audit or RATA according to section 11.1.1.4 of Performance Specification 15 and the requirements below. Perform the RATA of the HCl or HF CEMS at normal load. Acceptable HCl/HF reference methods (RM) are Methods 26 and 26A in appendix A–8 to part 60 of this chapter, Method 320 in Appendix A to this part, or ASTM D6348–03 (Reapproved 2010) “Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared

(FTIR) Spectroscopy" (incorporated by reference, see § 63.14), each applied based on the criteria set forth in Table 5 of this subpart.

3.1.2.1 When ASTM D6348–03 is used as the RM, the following conditions must be met:

3.1.2.1.1 The test plan preparation and implementation in the Annexes to ASTM D6348–03, Sections A1 through A8 are mandatory;

3.1.2.1.2 In ASTM D6348–03 Annex A5 (Analyte Spiking Technique), the percent (%) R must be determined for each target analyte (see Equation A5.5);

3.1.2.1.3 For the ASTM D6348–03 test data to be acceptable for a target analyte, %R must be 70% ≤R ≤130%; and

3.1.2.1.4 The %R value for each compound must be reported in the test report and all field measurements corrected with the calculated %R value for that compound using the following equation:

$$\text{Reported Result} = \frac{(\text{Measured Concentration in Stack})}{\%R} \times 100 \quad (\text{Eq. B-1})$$

3.1.2.2 The relative accuracy (RA) of the HCl or HF CEMS must be no greater than 20 percent of the mean value of the RM test data in units of ppm on the same moisture basis. Alternatively, if the mean RM value is less than 1.0 ppm, the RA results are acceptable if the absolute value of the difference between the mean RM and CEMS values does not exceed 0.20 ppm.

3.2 If you choose to follow PS 18 of appendix B to part 60 of this chapter, then your HCl CEMS must be certified according to PS 18, sections 7.0, 8.0, 11.0, 12.0, and 13.0.

3.3 Any additional stack gas flow rate, diluent gas, and moisture monitoring system(s) needed to express pollutant concentrations in units of the applicable emissions limit must be certified according to part 75 of this chapter.

#### 4. Recertification Procedures

Whenever the owner or operator makes a replacement, modification, or change to a certified CEMS that may significantly affect the ability of the system to accurately measure or record pollutant or diluent gas concentrations, stack gas flow rates, or stack gas moisture content, the owner or operator shall recertify the monitoring system. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit operation that may significantly change the concentration or flow profile, the owner or operator shall recertify the monitoring system. The same tests performed for the initial certification of the monitoring system shall be repeated for recertification, unless otherwise specified by the Administrator. Examples of changes that require recertification include: Replacement of a gas analyzer; complete monitoring system replacement, and changing the location or orientation of the sampling probe.

#### 5. On-Going Quality Assurance Requirements

On-going QA test requirements for HCl and HF CEMS must be implemented as follows:

5.1 If you choose to follow Performance Specification 15 (PS 15) of appendix B to part 60 of this chapter, then the quality assurance/quality control procedures of PS 15 shall apply as set forth in sections 5.1.1 through 5.1.3 and 5.4.2 of this appendix.

5.1.1 On a daily basis, you must assess the calibration error of the HCl or HF CEMS using either a calibration transfer standard as specified in Performance Specification 15 Section 10.1 which references Section 4.5 of the FTIR Protocol or a HCl and/or HF calibration gas at a concentration no greater than two times the level



corresponding to the applicable emission limit. A calibration transfer standard is a substitute calibration compound chosen to ensure that the FTIR is performing well at the wavelength regions used for analysis of the target analytes. The measured concentration of the calibration transfer standard or HCl and/or HF calibration gas results must agree within  $\pm 5$  percent of the reference gas value after correction for differences in pressure.

5.1.2 On a quarterly basis, you must conduct a gas audit of the HCl and/or HF CEMS as described in section 3.1.1 of this appendix. For the purposes of this appendix, "quarterly" means once every "QA operating quarter" (as defined in section 3.1.20 of appendix A to this subpart). You have the option to use HCl gas in lieu of HF gas for conducting this audit on an HF CEMS. To the extent practicable, perform consecutive quarterly gas audits at least 30 days apart. The initial quarterly audit is due in the first QA operating quarter following the calendar quarter in which certification testing of the CEMS is successfully completed. Up to three consecutive exemptions from the quarterly audit requirement are allowed for "non-QA operating quarters" (*i.e.*, calendar quarters in which there are less than 168 unit or stack operating hours). However, no more than four consecutive calendar quarters may elapse without performing a gas audit, except as otherwise provided in section 5.4.2.2.1 of this appendix.

5.1.3 You must perform an annual relative accuracy test audit or RATA of the HCl or HF CEMS as described in section 3.1.2 of this appendix. Perform the RATA at normal load. For the purposes of this appendix, "annual" means once every four "QA operating quarters" (as defined in section 3.1.20 of appendix A to this subpart). The first annual RATA is due within four QA operating quarters following the calendar quarter in which the initial certification testing of the HCl or HF CEMS is successfully completed. The provisions in section 5.1.2.4 of appendix A to this subpart pertaining to RATA deadline extensions also apply.

5.2 If you choose to follow Performance Specification PS 18 of appendix B to part 60 of this chapter, then the quality assurance/quality control procedures in Procedure 6 of appendix F to part 60 of this chapter shall apply. The quarterly and annual QA tests required under Procedure 6 shall be performed, respectively, at the frequencies specified in sections 5.1.2 and 5.1.3 of this appendix.

5.3 Stack gas flow rate, diluent gas, and moisture monitoring systems must meet the applicable on-going QA test requirements of part 75 of this chapter.

5.3.1 **Out-of-Control Periods.** A HCl or HF CEMS that is used to provide data under this appendix is considered to be out-of-control, and data from the CEMS may not be reported as quality-assured, when any acceptance criteria for a required QA test is not met. The HCl or HF CEMS is also considered to be out-of-control when a required QA test is not performed on schedule or within an allotted grace period. To end an out-of-control period, the QA test that was either failed or not done on time must be performed and passed. Out-of-control periods are counted as hours of monitoring system downtime.

5.3.2 **Grace Periods.** For the purposes of this appendix, a "grace period" is defined as a specified number of unit or stack operating hours after the deadline for a required quality-assurance test of a continuous monitor has passed, in which the test may be performed and passed without loss of data.

5.3.2.1 For the flow rate, diluent gas, and moisture monitoring systems described in section 5.2 of this appendix, a 168 unit or stack operating hour grace period is available for quarterly linearity checks, and a 720 unit or stack operating hour grace period is available for RATAs, as provided, respectively, in sections 2.2.4 and 2.3.3 of appendix B to part 75 of this chapter.

5.3.2.2 For the purposes of this appendix, if the deadline for a required gas audit or RATA of a HCl or HF CEMS cannot be met due to circumstances beyond the control of the owner or operator:

5.3.2.2.1 A 168 unit or stack operating hour grace period is available in which to perform the gas audit; or

5.3.2.2.2 A 720 unit or stack operating hour grace period is available in which to perform the RATA.

5.3.2.3 If a required QA test is performed during a grace period, the deadline for the next test shall be determined as follows:

5.3.2.3.1 For a gas audit or RATA of the monitoring systems described in section 5.1 of this appendix, determine the deadline for the next gas audit or RATA (as applicable) in accordance with section 2.2.4(b) or 2.3.3(d) of appendix B to part 75 of this chapter; treat a gas audit in the same manner as a linearity check.

5.3.2.3.2 For the gas audit of a HCl or HF CEMS, the grace period test only satisfies the audit requirement for the calendar quarter in which the test was originally due. If the calendar quarter in which the grace period audit is performed is a QA operating quarter, an additional gas audit is required for that quarter.

5.3.2.3.3 For the RATA of a HCl or HF CEMS, the next RATA is due within three QA operating quarters after the calendar quarter in which the grace period test is performed.

**5.3.3 Conditional Data Validation** For recertification and diagnostic testing of the monitoring systems that are used to provide data under this appendix, and for the required QA tests when non-redundant backup monitoring systems or temporary like-kind replacement analyzers are brought into service, the conditional data validation provisions in §§ 75.20(b)(3)(ii) through (b)(3)(ix) of this chapter may be used to avoid or minimize data loss. The allotted window of time to complete calibration tests and RATAs shall be as specified in § 75.20(b)(3)(iv) of this chapter; the allotted window of time to complete a gas audit shall be the same as for a linearity check (*i.e.*, 168 unit or stack operating hours).

#### **5.4 Data Validation.**

**5.4.1 Out-of-Control Periods.** An HCl or HF CEMS that is used to provide data under this appendix is considered to be out-of-control, and data from the CEMS may not be reported as quality-assured, when any acceptance criteria for a required QA test is not met. The HCl or HF CEMS is also considered to be out-of-control when a required QA test is not performed on schedule or within an allotted grace period. To end an out-of-control period, the QA test that was either failed or not done on time must be performed and passed. Out-of-control periods are counted as hours of monitoring system downtime.

**5.4.2 Grace Periods.** For the purposes of this appendix, a "grace period" is defined as a specified number of unit or stack operating hours after the deadline for a required quality-assurance test of a continuous monitor has passed, in which the test may be performed and passed without loss of data.

5.4.2.1 For the monitoring systems described in section 5.3 of this appendix, a 168 unit or stack operating hour grace period is available for quarterly linearity checks, and a 720 unit or stack operating hour grace period is available for RATAs, as provided, respectively, in sections 2.2.4 and 2.3.3 of appendix B to part 75 of this chapter.

5.4.2.2 For the purposes of this appendix, if the deadline for a required gas audit/data accuracy assessment or RATA of an HCl CEMS cannot be met due to circumstances beyond the control of the owner or operator:

5.4.2.2.1 A 168 unit or stack operating hour grace period is available in which to perform the gas audit or other quarterly data accuracy assessment; or

5.4.2.2.2 A 720 unit or stack operating hour grace period is available in which to perform the RATA.

5.4.2.3 If a required QA test is performed during a grace period, the deadline for the next test shall be determined as follows:

5.4.2.3.1 For a gas audit or RATA of the monitoring systems described in sections 5.1 and 5.2 of this appendix, determine the deadline for the next gas audit or RATA (as applicable) in accordance with section 2.2.4(b) or 2.3.3(d) of appendix B to part 75 of this chapter; treat a gas audit in the same manner as a linearity check.

5.4.2.3.2 For the gas audit or other quarterly data accuracy assessment of an HCl or HF CEMS, the grace period test only satisfies the audit requirement for the calendar quarter in which the test was originally due. If the calendar quarter in which the grace period audit is performed is a QA operating quarter, an additional gas audit/data accuracy assessment is required for that quarter.

5.4.2.3.3 For the RATA of an HCl or HF CEMS, the next RATA is due within three QA operating quarters after the calendar quarter in which the grace period test is performed.

5.4.3 **Conditional Data Validation.** For recertification and diagnostic testing of the monitoring systems that are used to provide data under this appendix, the conditional data validation provisions in § 75.20(b)(3)(ii) through (ix) of this chapter may be used to avoid or minimize data loss. The allotted window of time to complete calibration tests and RATAs shall be as specified in § 75.20(b)(3)(iv) of this chapter; the allotted window of time to complete a quarterly gas audit or data accuracy assessment shall be the same as for a linearity check (*i.e.*, 168 unit or stack operating hours).

## 6. Missing Data Requirements

For the purposes of this appendix, the owner or operator of an affected unit shall not substitute for missing data from HCl or HF CEMS. Any process operating hour for which quality-assured HCl or HF concentration data are not obtained is counted as an hour of monitoring system downtime.

## 7. Bias Adjustment

Bias adjustment of hourly emissions data from a HCl or HF CEMS is not required.

## 8. QA/QC Program Requirements

The owner or operator shall develop and implement a quality assurance/quality control (QA/QC) program for the HCl and/or HF CEMS that are used to provide data under this subpart. At a minimum, the program shall include a written plan that describes in detail (or that refers to separate documents containing) complete, step-by-step procedures and operations for the most important QA/QC activities. Electronic storage of the QA/QC plan is permissible, provided that the information can be made available in hard copy to auditors and inspectors. The QA/QC program requirements for the other monitoring systems described in section 5.3 of this appendix are specified in section 1 of appendix B to part 75 of this chapter.

### 8.1 **General Requirements for HCl and HF CEMS.**

8.1.1 **Preventive Maintenance.** Keep a written record of procedures needed to maintain the HCl and/or HF CEMS in proper operating condition and a schedule for those procedures. This shall, at a minimum, include procedures specified by the manufacturers of the equipment and, if applicable, additional or alternate procedures developed for the equipment.

8.1.2 **Recordkeeping and Reporting.** Keep a written record describing procedures that will be used to implement the recordkeeping and reporting requirements of this appendix.

8.1.3 **Maintenance Records.** Keep a record of all testing, maintenance, or repair activities performed on any HCl or HF CEMS in a location and format suitable for inspection. A maintenance log may be used for this purpose. The following records should be maintained: Date, time, and description of any testing, adjustment, repair, replacement, or preventive maintenance action performed on any monitoring system and records of any corrective actions associated with a monitor outage period. Additionally, any adjustment that may significantly affect a system's ability to accurately measure emissions data must be recorded and a written explanation of the procedures used to make the adjustment(s) shall be kept.

### 8.2 **Specific Requirements for HCl and HF CEMS.** The following requirements are specific to HCl and HF CEMS:

8.2.1 Keep a written record of the procedures used for each type of QA test required for each HCl and HF CEMS. Explain how the results of each type of QA test are calculated and evaluated.

8.2.2 Explain how each component of the HCl and/or HF CEMS will be adjusted to provide correct responses to calibration gases after routine maintenance, repairs, or corrective actions.

## 9. Data Reduction and Calculations

9.1 Design and operate the HCl and/or HF CEMS to complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

9.2 Reduce the HCl and/or HF concentration data to hourly averages in accordance with § 60.13(h)(2) of this chapter.

9.3 Convert each hourly average HCl or HF concentration to an HCl or HF emission rate expressed in units of the applicable emissions limit.

9.3.1 For heat input-based emission rates, select an appropriate emission rate equation from among Equations 19–1 through 19–9 in EPA Method 19 in Appendix A–7 to part 60 of this chapter, to calculate the HCl or HF emission rate in lb/MMBtu. Multiply the HCl concentration value (ppm) by  $9.43 \times 10^{-8}$  to convert it to lb/scf, for use in the applicable Method 19 equation. For HF, the conversion constant from ppm to lb/scf is  $5.18 \times 10^{-8}$ . The appropriate diluent cap value from section 6.2.1.2 of Appendix A to this subpart may be used to calculate the HCl or HF emission rate (lb/MMBtu) during startup or shutdown hours.

9.3.2 For gross output-based emission rates, first calculate the HCl or HF mass emission rate (lb/h), using an equation that has the general form of Equation A–2 or A–3 in appendix A to this subpart (as applicable), replacing the value of K with  $9.43 \times 10^{-8}$  lb/scf-ppm (for HCl) or  $5.18 \times 10^{-8}$  (for HF) and defining  $C_h$  as the hourly average HCl or HF concentration in ppm. Then, divide the result by the hourly gross output (megawatts) to convert it to units of lb/MWh. If the gross output is zero during a startup or shutdown hour, use the default gross output (as defined in § 63.10042) to calculate the HCl or HF emission rate. The default gross output is not considered to be a substitute data value.

9.4 Use Equation A–5 in appendix A of this subpart to calculate the required 30-boiler operating day rolling average HCl or HF emission rates. Report each 30-boiler operating day rolling average to the same precision as the standard (*i.e.*, with one leading non-zero digit and one decimal place), expressed in scientific notation. The term  $E_{ho}$  in Equation A–5 must be in the units of the applicable emissions limit.

## 10. Recordkeeping Requirements

10.1 For each HCl or HF CEMS installed at an affected source, and for any other monitoring system(s) needed to convert pollutant concentrations to units of the applicable emissions limit, the owner or operator must maintain a file of all measurements, data, reports, and other information required by this appendix in a form suitable for inspection, for 5 years from the date of each record, in accordance with § 63.10033. The file shall contain the information in paragraphs 10.1.1 through 10.1.8 of this section.

**10.1.1 Monitoring Plan Records.** For each affected unit or group of units monitored at a common stack, the owner or operator shall prepare and maintain a monitoring plan for the HCl and/or HF CEMS and any other monitoring system(s) (*i.e.*, flow rate, diluent gas, or moisture systems) needed to convert pollutant concentrations to units of the applicable emission standard. The monitoring plan shall contain essential information on the continuous monitoring systems and shall explain how the data derived from these systems ensure that all HCl or HF emissions from the unit or stack are monitored and reported.

**10.1.1.1 Updates.** Whenever the owner or operator makes a replacement, modification, or change in a certified continuous HCl or HF monitoring system that is used to provide data under this subpart (including a change in the automated data acquisition and handling system or the flue gas handling system) which affects information reported in the monitoring plan (e.g., a change to a serial number for a component of a monitoring system), the owner or operator shall update the monitoring plan.

**10.1.1.2 Contents of the Monitoring Plan.** For HCl and/or HF CEMS, the monitoring plan shall contain the applicable electronic and hard copy information in sections 10.1.1.2.1 and 10.1.1.2.2 of this appendix. For stack gas flow rate, diluent gas, and moisture monitoring systems, the monitoring plan shall include the electronic and hard copy information required for those systems under § 75.53 (g) of this chapter. The electronic monitoring plan shall be evaluated using the ECMPs Client Tool.

10.1.1.2.1 **Electronic.** Record the unit or stack ID number(s); monitoring location(s); the HCl or HF monitoring methodology used (*i.e.*, CEMS); HCl or HF monitoring system information, including, but not limited to: unique system and component ID numbers; the make, model, and serial number of the monitoring equipment; the sample acquisition method; formulas used to calculate emissions; monitor span and range information (if applicable).

10.1.1.2.2 **Hard Copy.** Keep records of the following: schematics and/or blueprints showing the location of the monitoring system(s) and test ports; data flow diagrams; test protocols; monitor span and range calculations (if applicable); miscellaneous technical justifications.

10.1.2 **Operating Parameter Records.** For the purposes of this appendix, the owner or operator shall record the following information for each operating hour of each affected unit or group of units utilizing a common stack, to the extent that these data are needed to convert pollutant concentration data to the units of the emission standard. For non-operating hours, record only the items in paragraphs 10.1.2.1 and 10.1.2.2 of this section. If there is heat input to the unit(s), but no electrical load, record only the items in paragraphs 10.1.2.1, 10.1.2.2, and (if applicable) 10.1.2.4 of this section.

10.1.2.1 The date and hour;

10.1.2.2 The unit or stack operating time (rounded up to the nearest fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator);

10.1.2.3 The hourly gross unit load (rounded to nearest MWge); and

10.1.2.4 If applicable, the F-factor used to calculate the heat input-based pollutant emission rate.

10.1.2.5 If applicable, a flag to indicate that the hour is a startup or shutdown hour (as defined in § 63.10042).

10.1.3 **HCl and/or HF Emissions Records.** For HCl and/or HF CEMS, the owner or operator must record the following information for each unit or stack operating hour:

10.1.3.1 The date and hour;

10.1.3.2 Monitoring system and component identification codes, as provided in the electronic monitoring plan, for each hour in which the CEMS provides a quality-assured value of HCl or HF concentration (as applicable);

10.1.3.3 The pollutant concentration, for each hour in which a quality-assured value is obtained. For HCl and HF, record the data in parts per million (ppm), with one leading non-zero digit and one decimal place, expressed in scientific notation. Use the following rounding convention: If the digit immediately following the first decimal place is 5 or greater, round the first decimal place upward (increase it by one); if the digit immediately following the first decimal place is 4 or less, leave the first decimal place unchanged.

10.1.3.4 A special code, indicating whether or not a quality-assured HCl or HF concentration value is obtained for the hour. This code may be entered manually when a temporary like-kind replacement HCl or HF analyzer is used for reporting; and

10.1.3.5 Monitor data availability, as a percentage of unit or stack operating hours, calculated according to § 75.32 of this chapter.

10.1.4 **Stack Gas Volumetric Flow Rate Records.**

10.1.4.1 Hourly measurements of stack gas volumetric flow rate during unit operation are required to demonstrate compliance with electrical output-based HCl or HF emissions limits (*i.e.*, lb/MWh or lb/GWh).

10.1.4.2 Use a flow rate monitor that meets the requirements of part 75 of this chapter to record the required data. You must keep hourly flow rate records, as specified in § 75.57(c)(2) of this chapter.

#### 10.1.5 **Records of Stack Gas Moisture Content.**

10.1.5.1 Correction of hourly pollutant concentration data for moisture is sometimes required when converting concentrations to the units of the applicable Hg emissions limit. In particular, these corrections are required:

10.1.5.1.1 To calculate electrical output-based pollutant emission rates, when using a CEMS that measures pollutant concentrations on a dry basis; and

10.1.5.1.2 To calculate heat input-based pollutant emission rates, when using certain equations from EPA Method 19 in appendix A-7 to part 60 of this chapter.

10.1.5.2 If hourly moisture corrections are required, either use a fuel-specific default moisture percentage for coal-fired units from § 75.11(b)(1) of this chapter, an Administrator approved default moisture value for non-coal-fired units (as per paragraph 63.10010(d) of this subpart), or a certified moisture monitoring system that meets the requirements of part 75 of this chapter, to record the required data. If you elect to use a moisture monitoring system, you must keep hourly records of the stack gas moisture content, as specified in § 75.57(c)(3) of this chapter.

#### 10.1.6 **Records of Diluent Gas (CO<sub>2</sub> or O<sub>2</sub>) Concentration.**

10.1.6.1 To assess compliance with a heat input-based HCl or HF emission rate limit in units of lb/MMBtu, hourly measurements of CO<sub>2</sub> or O<sub>2</sub> concentration are required to convert pollutant concentrations to units of the standard.

10.1.6.2 If hourly measurements of diluent gas concentration are needed, you must use a certified CO<sub>2</sub> or O<sub>2</sub> monitor that meets the requirements of part 75 of this chapter to record the required data. For all diluent gas monitors, you must keep hourly CO<sub>2</sub> or O<sub>2</sub> concentration records, as specified in § 75.57(g) of this chapter.

10.1.7 **HCl and HF Emission Rate Records.** For applicable HCl and HF emission limits in units of lb/MMBtu, lb/MWh, or lb/GWh, record the following information for each affected unit or common stack:

10.1.7.1 The date and hour;

10.1.7.2 The hourly HCl and/or HF emissions rate (lb/MMBtu, or lb/MWh, as applicable), for each hour in which valid values of HCl or HF concentration and all other required parameters (stack gas volumetric flow rate, diluent gas concentration, electrical load, and moisture data, as applicable) are obtained for the hour. Round off the emission rate to the same precision as the standard (*i.e.*, with one leading non-zero digit and one decimal place, expressed in scientific notation). Use the following rounding convention: If the digit immediately following the first decimal place is 5 or greater, round the first decimal place upward (increase it by one); if the digit immediately following the first decimal place is 4 or less, leave the first decimal place unchanged;

10.1.7.3 An identification code for the formula used to derive the hourly HCl or HF emission rate from HCl or HF concentration, flow rate, electrical load, diluent gas concentration, and moisture data (as applicable); and

10.1.7.4 A code indicating that the HCl or HF emission rate was not calculated for the hour, if valid data for HCl or HF concentration and/or any of the other necessary parameters are not obtained for the hour. For the purposes of this appendix, the substitute data values required under part 75 of this chapter for diluent gas concentration, stack gas flow rate and moisture content are not considered to be valid data.

10.1.7.5 If applicable, a code to indicate that the default electrical load (as defined in § 63.10042) was used to calculate the HCl or HF emission rate.

10.1.7.6 If applicable, a code to indicate that the diluent cap (as defined in § 63.10042) was used to calculate the HCl or HF emission rate.

10.1.8 **Certification and Quality Assurance Test Records.** For the HCl and/or HF CEMS used to provide data under this subpart at each affected unit (or group of units monitored at a common stack), record the following information for all required certification, recertification, diagnostic, and quality-assurance tests:

10.1.8.1 **HCl and HF CEMS.**

10.1.8.1.1 For each required 7-day and daily calibration drift test or daily calibration error test (including daily calibration transfer standard tests) of the HCl or HF CEMS, record the test date(s) and time(s), reference gas value(s), monitor response(s), and calculated calibration drift or calibration error value(s). If you use the dynamic spiking option for the mid-level calibration drift check under PS-18, you must also record the measured concentration of the native HCl in the flue gas before and after the spike and the spiked gas dilution factor. When using an IP-CEMS under PS-18, you must also record the measured concentrations of the native HCl before and after introduction of each reference gas, the path lengths of the calibration cell and the stack optical path, the stack and calibration cell temperatures, the instrument line strength factor, and the calculated equivalent concentration of reference gas.

10.1.8.1.2 For the required gas audits of an FTIR HCl or HF CEMS that is following PS 15, record the date and time of each spiked and unspiked sample, the audit gas reference values and uncertainties. Keep records of all calculations and data analyses required under sections 9.1 and 12.1 of Performance Specification 15, and the results of those calculations and analyses.

10.1.8.1.3 For each required RATA of an HCl or HF CEMS, record the beginning and ending date and time of each test run, the reference method(s) used, and the reference method and HCl or HF CEMS run values. Keep records of stratification tests performed (if any), all of the raw field data, relevant process operating data, and all of the calculations used to determine the relative accuracy.

10.1.8.1.4 For each required beam intensity test of an HCl IP-CEMS under PS-18, record the test date and time, the known attenuation value (%) used for the test, the concentration of the high-level reference gas used, the full-beam and attenuated beam intensity levels, the measured HCl concentrations at full-beam intensity and attenuated intensity and the percent difference between them, and the results of the test. For each required daily beam intensity check of an IP-CEMS under Procedure 6, record the beam intensity measured including the units of measure and the results of the check.

10.1.8.1.5 For each required measurement error (ME) test of an HCl monitor, record the date and time of each gas injection, the reference gas concentration (low, mid, or high) and the monitor response for each of the three injections at each of the three levels. Also record the average monitor response and the ME at each gas level and the related calculations. For ME tests conducted on IP-CEMS, also record the measured concentrations of the native HCl before and after introduction of each reference gas, the path lengths of the calibration cell and the stack optical path, the stack and calibration cell temperatures, the stack and calibration cell pressures, the instrument line strength factor, and the calculated equivalent concentration of reference gas.

10.1.8.1.6 For each required level of detection (LOD) test of an HCl monitor performed in a controlled environment, record the test date, the concentrations of the reference gas and interference gases, the results of the seven (or more) consecutive measurements of HCl, the standard deviation, and the LOD value. For each required LOD test performed in the field, record the test date, the three measurements of the native source HCl concentration, the results of the three independent standard addition (SA) measurements known as standard addition response (SAR), the effective spike addition gas concentration (for IP-CEMS, the equivalent concentration of the reference gas), the resulting standard addition detection level (SADL) value and all related calculations. For extractive CEMS performing the SA using dynamic spiking, you must record the spiked gas dilution factor.

10.1.8.1.7 For each required ME/level of detection response time test of an HCl monitor, record the test date, the native HCl concentration of the flue gas, the reference gas value, the stable reference gas readings, the upscale/downscale start and end times, and the results of the upscale and downscale stages of the test.

10.1.8.1.8 For each required temperature or pressure measurement verification or audit of an IP-CEMS, keep records of the test date, the temperatures or pressures (as applicable) measured by the calibrated temperature or pressure reference device and the IP-CEMS, and the results of the test.

10.1.8.1.9 For each required interference test of an HCl monitor, record (or obtain from the analyzer manufacturer records of): The date of the test; the gas volume/rate, temperature, and pressure used to conduct the test; the HCl concentration of the reference gas used; the concentrations of the interference test gases; the baseline HCl and HCl responses for each interferent combination spiked; and the total percent interference as a function of span or HCl concentration.

10.1.8.1.10 For each quarterly relative accuracy audit (RAA) of an HCl monitor, record the beginning and ending date and time of each test run, the reference method used, the HCl concentrations measured by the reference method and CEMS for each test run, the average concentrations measured by the reference method and the CEMS, and the calculated relative accuracy. Keep records of the raw field data, relevant process operating data, and the calculations used to determine the relative accuracy.

10.1.8.1.11 For each quarterly cylinder gas audit (CGA) of an HCl monitor, record the date and time of each injection, and the reference gas concentration (zero, mid, or high) and the monitor response for each injection. Also record the average monitor response and the calculated ME at each gas level. For IP-CEMS, you must also record the measured concentrations of the native HCl before and after introduction of each reference gas, the path lengths of the calibration cell and the stack optical path, the stack and calibration cell temperatures, the stack and calibration cell pressures, the instrument line strength factor, and the calculated equivalent concentration of reference gas.

10.1.8.1.12 For each quarterly dynamic spiking audit (DSA) of an HCl monitor, record the date and time of the zero gas injection and each spike injection, the results of the zero gas injection, the gas concentrations (mid and high) and the dilution factors and the monitor response for each of the six upscale injections as well as the corresponding native HCl concentrations measured before and after each injection. Also record the average dynamic spiking error for each of the upscale gases, the calculated average DSA Accuracy at each upscale gas concentration, and all calculations leading to the DSA Accuracy.

10.1.8.2 **Additional Monitoring Systems.** For the stack gas flow rate, diluent gas, and moisture monitoring systems described in section 3.2 of this appendix, you must keep records of all certification, recertification, diagnostic, and on-going quality-assurance tests of these systems, as specified in § 75.59(a) of this chapter.

## 11. Reporting Requirements

11.1 **General Reporting Provisions.** The owner or operator shall comply with the following requirements for reporting HCl and/or HF emissions from each affected unit (or group of units monitored at a common stack):

11.1.1 Notifications, in accordance with paragraph 11.2 of this section;

11.1.2 Monitoring plan reporting, in accordance with paragraph 11.3 of this section;

11.1.3 Certification, recertification, and QA test submittals, in accordance with paragraph 11.4 of this section;  
and

11.1.4 Electronic quarterly report submittals, in accordance with paragraph 11.5 of this section.

11.2 **Notifications.** The owner or operator shall provide notifications for each affected unit (or group of units monitored at a common stack) in accordance with § 63.10030.

11.3 **Monitoring Plan Reporting.** For each affected unit (or group of units monitored at a common stack) using HCl and/or HF CEMS, the owner or operator shall make electronic and hard copy monitoring plan submittals as follows:



11.3.1 For an EGU that begins reporting hourly HCl and/or HF concentrations with a previously-certified CEMS, submit the monitoring plan information in section 10.1.1.2 of this appendix prior to or concurrent with the first required quarterly emissions report. For a new EGU, or for an EGU switching to continuous monitoring of HCl and/or HF emissions after having implemented another allowable compliance option under this subpart, submit the information in section 10.1.1.2 of this appendix at least 21 days prior to the start of initial certification testing of the CEMS. Also submit the monitoring plan information in section 75.53(g) pertaining to any required flow rate, diluent gas, and moisture monitoring systems within the applicable time frame specified in this section, if the required records are not already in place.

11.3.2 Update the monitoring plan when required, as provided in paragraph 10.1.1.1 of this appendix. An electronic monitoring plan information update must be submitted either prior to or concurrent with the quarterly report for the calendar quarter in which the update is required.

11.3.3 All electronic monitoring plan submittals and updates shall be made to the Administrator using the ECMPS Client Tool. Hard copy portions of the monitoring plan shall be kept on record according to section 10.1 of this appendix.

**11.4 Certification, Recertification, and Quality-Assurance Test Reporting Requirements.** Except for daily QA tests (*i.e.*, calibrations and flow monitor interference checks), which are included in each electronic quarterly emissions report, use the ECMPS Client Tool to submit the results of all required certification, recertification, quality-assurance, and diagnostic tests of the monitoring systems required under this appendix electronically. Submit the test results either prior to or concurrent with the relevant quarterly electronic emissions report. However, for RATAs of the HCl monitor, if this is not possible, you have up to 60 days after the test completion date to submit the test results; in this case, you may claim provisional status for the emissions data affected by the test, starting from the date and hour in which the test was completed and continuing until the date and hour in which the test results are submitted. If the test is successful, the status of the data in that time period changes from provisional to quality-assured, and no further action is required. However, if the test is unsuccessful, the provisional data must be invalidated and resubmission of the affected emission report(s) is required.

11.4.1 For each daily calibration drift (or calibration error) assessment (including daily calibration transfer standard tests), and for each 7-day calibration drift test of an HCl or HF monitor, report:

11.4.1.1 Facility ID information;

11.4.1.2 The monitoring component ID;

11.4.1.3 The instrument span and span scale;

11.4.1.4 For each gas injection, the date and time, the calibration gas level (zero, mid or other), the reference gas value (ppm), and the monitor response (ppm);

11.4.1.5 A flag to indicate whether dynamic spiking was used for the upscale value (extractive HCl monitors only);

11.4.1.6 Calibration drift or calibration error (percent of span or reference gas, as applicable);

11.4.1.7 When using the dynamic spiking option, the measured concentration of native HCl before and after each mid-level spike and the spiked gas dilution factor;

11.4.1.8 When using an IP-CEMS, also report the measured concentration of native HCl before and after each upscale measurement, the path lengths of the calibration cell and the stack optical path, the stack and calibration cell temperatures, the stack and calibration cell pressures, the instrument line strength factor, and the equivalent concentration of the reference gas; and

11.4.1.9 Reason for test (for the 7-day CD test, only).

11.4.2 For each quarterly gas audit of an HCl or HF CEMS that is following PS 15, report:

11.4.2.1 Facility ID information;

11.4.2.2 Monitoring system ID number;

11.4.2.3 Type of test (e.g., quarterly gas audit);

11.4.2.4 Reason for test;

11.4.2.5 Certified audit (spike) gas concentration value (ppm);

11.4.2.6 Measured value of audit (spike) gas, including date and time of injection;

11.4.2.7 Calculated dilution ratio for audit (spike) gas;

11.4.2.8 Date and time of each spiked flue gas sample;

11.4.2.9 Date and time of each unspiked flue gas sample;

11.4.2.10 The measured values for each spiked gas and unspiked flue gas sample (ppm);

11.4.2.11 The mean values of the spiked and unspiked sample concentrations and the expected value of the spiked concentration as specified in section 12.1 of Performance Specification 15 (ppm);

11.4.2.12 Bias at the spike level as calculated using equation 3 in section 12.1 of Performance Specification 15; and

11.4.2.13 The correction factor (CF), calculated using equation 6 in section 12.1 of Performance Specification 15.

11.4.3 For each RATA of a HCl or HF CEMS, report:

11.4.3.1 Facility ID information;

11.4.3.2 Monitoring system ID number;

11.4.3.3 Type of test (*i.e.*, initial or annual RATA);

11.4.3.4 Reason for test;

11.4.3.5 The reference method used;

11.4.3.6 Starting and ending date and time for each test run;

11.4.3.7 Units of measure;

11.4.3.8 The measured reference method and CEMS values for each test run, on a consistent moisture basis, in appropriate units of measure;

11.4.3.9 Flags to indicate which test runs were used in the calculations;

11.4.3.10 Arithmetic mean of the CEMS values, of the reference method values, and of their differences;

11.4.3.11 Standard deviation, using either Equation 2–4 in section 12.3 of PS 2 in appendix B to part 60 of this chapter or Equation 10 in section 12.6.5 of PS 18;

11.4.3.12 Confidence coefficient, using either Equation 2–5 in section 12.4 of PS 2 in appendix B to part 60 of this chapter or Equation 11 in section 12.6.6 of PS 18;

11.4.3.13 t-value; and

11.4.3.14 Relative accuracy calculated using Equation 2–6 of Performance Specification 2 in appendix B to part 60 of this chapter or, if applicable, according to the alternative procedure for low emitters described in section 3.1.2.2 of this appendix. If applicable use a flag to indicate that the alternative RA specification for low emitters has been applied.

11.4.4 For each 3-level ME test of an HCl monitor, report:

11.4.4.1 Facility ID information;

11.4.4.2 Monitoring component ID;

11.4.4.3 Instrument span and span scale;

11.4.4.4 For each gas injection, the date and time, the calibration gas level (low, mid, or high), the reference gas value in ppm and the monitor response. When using an IP–CEMS, also report the measured concentration of native HCl before and after each injection, the path lengths of the calibration cell and the stack optical path, the stack and calibration cell temperatures, the stack and calibration cell pressures, the instrument line strength factor, and the equivalent concentration of the reference gas;

11.4.4.5 For extractive CEMS, the mean reference value and mean of measured values at each reference gas level (ppm). For IP–CEMS, the mean of the measured concentration minus the average measured native concentration minus the equivalent reference gas concentration (ppm), at each reference gas level—see Equation 6A in PS 18;

11.4.4.6 ME at each reference gas level; and

11.4.4.7 Reason for test.

11.4.5 Beam intensity tests of an IP CEMS:

11.4.5.1 For the initial beam intensity test described in PS 18 in appendix B to part 60 of this chapter, report:

11.4.5.1.1 Facility ID information;

11.4.5.1.2 Date and time of the test;

11.4.5.1.3 Monitoring system ID;

11.4.5.1.4 Reason for test;

11.4.5.1.5 Attenuation value (%);

11.4.5.1.6 High level gas concentration (ppm);

11.4.5.1.7 Full and attenuated beam intensity levels, including units of measure;

11.4.5.1.8 Measured HCl concentrations at full and attenuated beam intensity (ppm); and

11.4.5.1.9 Percentage difference between the HCl concentrations.

11.4.5.2 For the daily beam intensity check described in Procedure 6 of appendix F to Part 60 of this chapter, report:

11.4.5.2.1 Facility ID information;

11.4.5.2.2 Date and time of the test;

11.4.5.2.3 Monitoring system ID;

11.4.5.2.4 The attenuated beam intensity level (limit) established in the initial test;

11.4.5.2.5 The beam intensity measured during the daily check; and

11.4.5.2.6 Results of the test (pass or fail).

11.4.6 For each temperature or pressure verification or audit of an HCl IP-CEMS, report:

11.4.6.1 Facility ID information;

11.4.6.2 Date and time of the test;

11.4.6.3 Monitoring system ID;

11.4.6.4 Type of verification (temperature or pressure);

11.4.6.5 Stack sensor measured value;

11.4.6.6 Reference device measured value;

11.4.6.7 Results of the test (pass or fail); and

11.4.6.8 Reason for test.

11.4.7 For each interference test of an HCl monitoring system, report:

11.4.7.1 Facility ID information;

11.4.7.2 Date of test;

11.4.7.3 Monitoring system ID;

11.4.7.4 Results of the test (pass or fail);

11.4.7.5 Reason for test; and

11.4.7.6 A flag to indicate whether the test was performed: On this particular monitoring system; on one of multiple systems of the same type; or by the manufacturer on a system with components of the same make and model(s) as this system.

11.4.8 For each LOD test of an HCl monitor, report:

11.4.8.1 Facility ID information;

11.4.8.2 Date of test;

11.4.8.3 Reason for test;

11.4.8.4 Monitoring system ID;

11.4.8.5 A code to indicate whether the test was done in a controlled environment or in the field;

11.4.8.6 HCl reference gas concentration;

11.4.8.7 HCl responses with interference gas (seven repetitions);

11.4.8.8 Standard deviation of HCl responses;

11.4.8.9 Effective spike addition gas concentrations;

11.4.8.10 HCl concentration measured without spike;

11.4.8.11 HCl concentration measured with spike;

11.4.8.12 Dilution factor for spike;

11.4.8.13 The controlled environment LOD value (ppm or ppm-meters);

11.4.8.14 The field determined standard addition detection level (SADL in ppm or ppm-meters); and

11.4.8.15 Result of LDO/SADL test (pass/fail).

11.4.9 For each ME or LOD response time test of an HCl monitor, report:

11.4.9.1 Facility ID information;

11.4.9.2 Date of test;

11.4.9.3 Monitoring component ID;

11.4.9.4 The higher of the upscale or downscale tests, in minutes; and

11.4.9.5 Reason for test.

11.4.10 For each quarterly RAA of an HCl monitor, report:

11.4.10.1 Facility ID information;

11.4.10.2 Monitoring system ID;

11.4.10.3 Begin and end time of each test run;

11.4.10.4 The reference method used;

- 11.4.10.5 The reference method and CEMS values for each test run, including the units of measure;
  - 11.4.10.6 The mean reference method and CEMS values for the three test runs;
  - 11.4.10.7 The calculated relative accuracy, percent; and
  - 11.4.10.8 Reason for test.
- 11.4.11 For each quarterly cylinder gas audit of an HCl monitor, report:
- 11.4.11.1 Facility ID information;
  - 11.4.11.2 Monitoring component ID;
  - 11.4.11.3 Instrument span and span scale;
  - 11.4.11.4 For each gas injection, the date and time, the reference gas level (zero, mid, or high), the reference gas value in ppm, and the monitor response. When using an IP-CEMS, also report the measured concentration of native HCl before and after each injection, the path lengths of the calibration cell and the stack optical path, the stack and calibration cell temperatures, the stack and calibration cell pressures, the instrument line strength factor, and the equivalent concentration of the reference gas;
  - 11.4.11.5 For extractive CEMS, the mean reference gas value and mean monitor response at each reference gas level (ppm). For IP-CEMS, the mean of the measured concentration minus the average measured native concentration minus the equivalent reference gas concentration (ppm), at each reference gas level -see Equation 6A in PS 18;
  - 11.4.11.6 ME at each reference gas level; and
  - 11.4.11.7 Reason for test.
- 11.4.12 For each quarterly DSA of an HCl monitor, report:
- 11.4.12.1 Facility ID information;
  - 11.4.12.2 Monitoring component ID;
  - 11.4.12.3 Instrument span and span scale;
  - 11.4.12.4 For the zero gas injection, the date and time, and the monitor response (*Note: The zero gas injection from a calibration drift check performed on the same day as the upscale spikes may be used for this purpose.*);
  - 11.4.12.5 Zero spike error;
  - 11.4.12.6 For the upscale gas spiking, the date and time of each spike, the reference gas level (mid- or high-), the reference gas value (ppm), the dilution factor, the native HCl concentrations before and after each spike, and the monitor response for each gas spike;
  - 11.4.12.7 Upscale spike error;
  - 11.4.12.8 DSA at the zero level and at each upscale gas level; and
  - 11.4.12.9 Reason for test.

11.4.13 **Reporting Requirements for Diluent Gas, Flow Rate, and Moisture Monitoring Systems.** For the certification, recertification, diagnostic, and QA tests of stack gas flow rate, moisture, and diluent gas monitoring systems that are certified and quality-assured according to part 75 of this chapter, report the information in section 10.1.8.2 of this appendix.

#### 11.5 **Quarterly Reports.**

11.5.1 The owner or operator of any affected unit shall use the ECMPs Client Tool to submit electronic quarterly reports to the Administrator in an XML format specified by the Administrator, for each affected unit (or group of units monitored at a common stack). If the certified HCl or HF CEMS is used for the initial compliance demonstration, HCl or HF emissions reporting shall begin with the first operating hour of the 30-boiler operating day compliance demonstration period. Otherwise, HCl or HF emissions reporting shall begin with the first operating hour after successfully completing all required certification tests of the CEMS.

11.5.2 The electronic reports must be submitted within 30 days following the end of each calendar quarter, except for units that have been placed in long-term cold storage.

11.5.3 Each electronic quarterly report shall include the following information:

11.5.3.1 The date of report generation;

11.5.3.2 Facility identification information;

11.5.3.3 The information in sections 10.1.2 through 10.1.7 of this appendix, as applicable to the type(s) of monitoring system(s) used to measure the pollutant concentrations and other necessary parameters.

11.5.3.4 The results of all daily calibrations (including calibration transfer standard tests) of the HCl or HF monitor as described in section 10.1.8.1.1 of this appendix; and

11.5.3.5 If applicable, the results of all daily flow monitor interference checks, in accordance with section 10.1.8.2 of this appendix.

11.5.4 **Compliance Certification.** Based on reasonable inquiry of those persons with primary responsibility for ensuring that all HCl and/or HF emissions from the affected unit(s) have been correctly and fully monitored, the owner or operator shall submit a compliance certification in support of each electronic quarterly emissions monitoring report. The compliance certification shall include a statement by a responsible official with that official's name, title, and signature, certifying that, to the best of his or her knowledge, the report is true, accurate, and complete.

[77 FR 9464, Feb. 16, 2012, as amended at 78 FR 24094, Apr. 24, 2013; 79 FR 68795, Nov. 19, 2014; 81 FR 20205, Apr. 6, 2016; 85 FR 55766, Sept. 9, 2020]

### **Appendix C to Subpart UUUUU of Part 63—PM Monitoring Provisions**

#### 1. General Provisions

1.1 **Applicability.** These monitoring provisions apply to the continuous measurement of filterable PM emissions from affected EGUs under this subpart. A PM CEMS is used together with other CMS and (as applicable) parametric measurement devices to quantify PM emissions in units of the applicable standard (*i.e.*, lb/MMBtu or lb/MWh).

#### 1.2 **Initial Certification and Recertification Procedures.**

You, as the owner or operator of an affected EGU that uses a PM CEMS to demonstrate compliance with a filterable PM emissions limit in Table 1 or 2 to this subpart must certify and, if applicable, recertify the CEMS according to PS-11 in appendix B to part 60 of this chapter.

**1.3 Quality Assurance and Quality Control Requirements.** You must meet the applicable quality assurance requirements of Procedure 2 in appendix F to part 60 of this chapter.

**1.4 Missing Data Procedures.** You must not substitute data for missing data from the PM CEMS. Any process operating hour for which quality-assured PM concentration data are not obtained is counted as an hour of monitoring system downtime.

**1.5 Adjustments for Flow System Bias.** When the PM emission rate is reported on a gross output basis, you must not adjust the data recorded by a stack gas flow rate monitor for bias, which may otherwise be required under section 75.24 of this chapter.

## 2. Monitoring of PM Emissions

**2.1 Monitoring System Installation Requirements.** Flue gases from the affected EGUs under this subpart vent to the atmosphere through a variety of exhaust configurations including single stacks, common stack configurations, and multiple stack configurations. For each of these configurations, 40 CFR 63.10010(a) specifies the appropriate location(s) at which to install CMS. These CMS installation provisions apply to the PM CEMS and to the other CMS and parametric monitoring devices that provide data for the PM emissions calculations in section 6 of this appendix.

**2.2 Primary and Backup Monitoring Systems.** In the electronic monitoring plan described in section 7 of this appendix, you must create and designate a primary monitoring system for PM and for each additional parameter (*i.e.*, stack gas flow rate, CO<sub>2</sub> or O<sub>2</sub> concentration, stack gas moisture content, as applicable). The primary system must be used to report hourly PM concentration values when the system is able to provide quality-assured data, *i.e.*, when the system is "in control." However, to increase data availability in the event of a primary monitoring system outage, you may install, operate, maintain, and calibrate a redundant backup monitoring system. A redundant backup system is one that is permanently installed at the unit or stack location and is kept on "hot standby" in case the primary monitoring system is unable to provide quality-assured data. You must represent each redundant backup system as a unique monitoring system in the electronic monitoring plan. You must certify each redundant backup monitoring system according to the applicable provisions in section 4 of this appendix. In addition, each redundant monitoring system must meet the applicable on-going QA requirements in section 5 of this appendix.

## 3. PM Emissions Measurement Methods

The following definitions, equipment specifications, procedures, and performance criteria are applicable

**3.1 Definitions.** All definitions specified in section 3 of PS-11 in appendix B to part 60 of this chapter and section 3 of Procedure 2 in appendix F to part 60 of this chapter are applicable to the measurement of filterable PM emissions from electric utility steam generating units under this subpart. In addition, the following definitions apply:

**3.1.1 Stack operating hour** means a clock hour during which flue gases flow through a particular stack or duct (either for the entire hour or for part of the hour) while the associated unit(s) are combusting fuel.

**3.1.2 Unit operating hour** means a clock hour during which a unit combusts any fuel, either for part of the hour or for the entire hour.

### 3.2 Continuous Monitoring Methods.

**3.2.1 Installation and Measurement Location.** You must install the PM CEMS according to 40 CFR 63.10010 and Section 2.4 of PS-11.

**3.2.2 Units of Measure.** For the purposes of this subpart, you shall report hourly PM concentrations in units of measure that correspond to your PM CEMS correlation curve (*e.g.*, mg/acm, mg/acm @ 160 °C, mg/wscm, mg/dscm).



3.2.3 Other Necessary Data Collection. To convert hourly PM concentrations to the units of the applicable emissions standard (*i.e.*, lb/MMBtu or lb/MWh), you must collect additional data as described in sections 3.2.3.1 and 3.2.3.2 of this appendix. You must install, certify, operate, maintain, and quality-assure any stack gas flow rate, CO<sub>2</sub>, O<sub>2</sub>, or moisture monitoring systems needed for this purpose according to sections 4 and 5 of this appendix. The calculation methods for the emission limits described in sections 3.2.3.1 and 3.2.3.2 of this appendix are presented in section 6 of this appendix.

3.2.3.1 Heat Input-Based Emission Limits. To demonstrate compliance with a heat input-based PM emission limit in Table 2 to this subpart, you must provide the hourly stack gas CO<sub>2</sub> or O<sub>2</sub> concentration, along with a fuel-specific F<sub>c</sub> factor or dry-basis F-factor and (if applicable) the stack gas moisture content, in order to convert measured PM concentrations values to the units of the standard.

3.2.3.2 Gross Output-Based Emission Limits. To demonstrate compliance with a gross output-based PM emission limit in Table 1 or Table 2 to this subpart, you must provide the hourly gross output in megawatts, along with data from a certified stack gas flow rate monitor and (if applicable) the stack gas moisture content, in order to convert measured PM concentrations values to units of the standard.

#### 4. Certification and Recertification Requirements

4.1 **Certification Requirements.** You must certify your PM CEMS and the other CMS used to determine compliance with the applicable emissions standard before the PM CEMS can be used to provide data under this subpart. Redundant backup monitoring systems (if used) are subject to the same certification requirements as the primary systems.

4.1.1 PM CEMS. You must certify your PM CEMS according to PS–11 in appendix B to part 60 of this chapter. A PM CEMS that has been installed and certified according to PS–11 as a result of another state or federal regulatory requirement or consent decree prior to the effective date of this subpart shall be considered certified for this subpart if you can demonstrate that your PM CEMS meets the PS–11 acceptance criteria based on the applicable emission standard in this subpart.

4.1.2 Flow Rate, Diluent Gas, and Moisture Monitoring Systems. You must certify the continuous monitoring systems that are needed to convert PM concentrations to units of the standard or (if applicable) to convert the measured PM concentrations from wet basis to dry basis or vice-versa (*i.e.*, stack gas flow rate, diluent gas (CO<sub>2</sub> or O<sub>2</sub>) concentration, or moisture monitoring systems), in accordance with the applicable provisions in section 75.20 of this chapter and appendix A to part 75 of this chapter.

4.1.3 Other Parametric Measurement Devices. Any temperature or pressure measurement devices that are used to convert hourly PM concentrations to standard conditions must be installed, calibrated, maintained, and operated according to the manufacturers' instructions.

#### 4.2 Recertification.

4.2.1 You must recertify your PM CEMS if it is either: moved to a different stack or duct; moved to a new location within the same stack or duct; modified or repaired in such a way that the existing correlation is altered or impacted; or replaced.

4.2.2 The flow rate, diluent gas, and moisture monitoring systems that are used to convert PM concentration to units of the emission standard are subject to the recertification provisions in section 75.20(b) of this chapter.

4.3 **Development of a New or Revised Correlation Curve.** You must develop a new or revised correlation curve if:

4.3.1 An RCA is failed and the new or revised correlation is developed according to section 10.6 in Procedure 2 of appendix F to part 60 of this chapter; or

4.3.2 The events described in paragraph (1) or (2) in section 8.8 of PS–11 occur.

## 5. Ongoing Quality Assurance (QA) and Data Validation

### 5.1 **PM CEMS.**

5.1.1 Required QA Tests. Following initial certification, you must conduct periodic QA testing of each primary and (if applicable) redundant backup PM CEMS. The required QA tests and the PS that must be met are found in Procedure 2 of appendix F to part 60 of this chapter (Procedure 2). Except as otherwise provided in section 5.1.2 of this appendix, the QA tests shall be done at the frequency specified in Procedure 2.

#### 5.1.2 RRA and RCA Test Frequencies.

5.1.2.1 The test frequency for RRAs of the PM CEMS shall be annual, *i.e.*, once every 4 calendar quarters. The RRA must either be performed within the fourth calendar quarter after the calendar quarter in which the previous RRA was completed or in a grace period (see section 5.1.3, below). When a required annual RRA is done within a grace period, the deadline for the next RRA is 4 calendar quarters after the quarter in which the RRA was originally due, rather than the calendar quarter in which the grace period test is completed.

5.1.2.2 The test frequency for RCAs of the PM CEMS shall be triennial, *i.e.*, once every 12 calendar quarters. If a required RCA is not completed within 12 calendar quarters after the calendar quarter in which the previous RCA was completed, it must be performed in a grace period immediately following the twelfth calendar quarter (see section 5.1.3, below). When an RCA is done in a grace period, the deadline for the next RCA shall be 12 calendar quarters after the calendar quarter in which the RCA was originally due, rather than the calendar quarter in which the grace period test is completed.

5.1.2.3 Successive quarterly audits (*i.e.*, ACAs and, if applicable, sample volume audits (SVAs)) shall be conducted at least 60 days apart.

5.1.3 Grace Period. A grace period is available, immediately following the end of the calendar quarter in which an RRA or RCA of the PM CEMS is due. The length of the grace period shall be the lesser of 720 EGU (or stack) operating hours or 1 calendar quarter.

5.1.4 RCA and RRA Acceptability. The results of your RRA or RCA are considered acceptable provided that the criteria in section 10.4(5) of Procedure 2 in appendix F to part 60 of this chapter are met for an RCA or section 10.4(6) of Procedure 2 in appendix F to part 60 of this chapter are met for an RRA.

5.1.5 Data Validation. Your PM CEMS is considered to be out-of-control, and you may not report data from it as quality-assured, when, for a required certification, recertification, or QA test, the applicable acceptance criterion (either in PS-11 in appendix B to part 60 of this chapter or Procedure 2 in appendix F to part 60 of this chapter) is not met. Further, data from your PM CEMS are considered out-of-control, and may not be used for reporting, when a required QA test is not performed on schedule or within an allotted grace period. When an out-of-control period occurs, you must perform the appropriate follow-up actions. For an out-of-control period triggered by a failed QA test, you must perform and pass the same type of test in order to end the out-of-control period. For a QA test that is not performed on time, data from the PM CEMS remain out-of-control until the required test has been performed and passed. You must count all out-of-control data periods of the PM CEMS as hours of monitoring system downtime.

5.2 **Stack Gas Flow Rate, Diluent Gas, and Moisture Monitoring Systems.** The on-going QA test requirements and data validation criteria for the primary and (if applicable) redundant backup stack gas flow rate, diluent gas, and moisture monitoring systems are specified in appendix B to part 75 of this chapter.

5.3 **QA/QC Program Requirements.** You must develop and implement a QA/QC program for the PM CEMS and the other equipment that is used to provide data under this subpart. You may store your QA/QC plan electronically, provided that the information can be made available expeditiously in hard copy to auditors and inspectors.

### 5.3.1 General Requirements.

5.3.1.1 Preventive Maintenance. You must keep a written record of the procedures needed to maintain the PM CEMS and other equipment that is used to provide data under this subpart in proper operating condition, along with a schedule for those procedures. At a minimum, you must include all procedures specified by the manufacturers of the equipment and, if applicable, additional or alternate procedures developed for the equipment.

5.3.1.2 Recordkeeping Requirements. You must keep a written record describing procedures that will be used to implement the recordkeeping and reporting requirements of this appendix.

5.3.1.3 Maintenance Records. You must keep a record of all testing, maintenance, or repair activities performed on the PM CEMS, and other equipment used to provide data under this subpart in a location and format suitable for inspection. You may use a maintenance log for this purpose. You must maintain the following records for each system or device: The date, time, and description of any testing, adjustment, repair, replacement, or preventive maintenance action performed, and records of any corrective actions taken. Additionally, you must record any adjustment that may affect the ability of a monitoring system or measurement device to make accurate measurements, and you must keep a written explanation of the procedures used to make the adjustment(s).

### 5.3.2 Specific Requirements for the PM CEMS.

5.3.2.1 Daily, and Quarterly Quality Assurance Assessments. You must keep a written record of the procedures used for daily assessments of the PM CEMS. You must also keep records of the procedures used to perform quarterly ACA and (if applicable) SVA audits. You must document how the test results are calculated and evaluated.

5.3.2.2 Monitoring System Adjustments. You must document how each component of the PM CEMS will be adjusted to provide correct responses after routine maintenance, repairs, or corrective actions.

5.3.2.3 Correlation Tests, Annual and Triennial Audits. You must keep a written record of procedures used for the correlation test(s), annual RRAs, and triennial RCAs of the PM CEMS. You must document how the test results are calculated and evaluated.

5.3.3 Specific Requirements for Diluent Gas, Stack Gas Flow Rate, and Moisture Monitoring Systems. The QA/QC program requirements for the stack gas flow rate, diluent gas, and moisture monitoring systems described in section 3.2.3 of this appendix are specified in section 1 of appendix B to part 75 of this chapter.

5.3.4 Requirements for Other Monitoring Equipment. For the equipment required to convert readings from the PM CEMS to standard conditions (e.g., devices to measure temperature and pressure), you must keep a written record of the calibrations and/or other procedures used to ensure that the devices provide accurate data.

5.3.5 You may store your QA/QC plan electronically, provided that you can make the information available expeditiously in hard copy to auditors or inspectors.

## 6. Data Reduction and Calculations

### 6.1 **Data Reduction and Validation.**

6.1.1 You must reduce the data from PM CEMS to hourly averages, in accordance with 40 CFR 60.13(h)(2) of this chapter.

6.1.2 You must reduce all CEMS data from stack gas flow rate, CO<sub>2</sub>, O<sub>2</sub>, and moisture monitoring systems to hourly averages according to 40 CFR 75.10(d)(1) of this chapter.

6.1.3 You must reduce all other data from devices used to convert readings from the PM CEMS to standard conditions to hourly averages according to 40 CFR 60.13(h)(2) or 40 CFR 75.10(d)(1) of this chapter. This includes, but is not limited to, data from devices used to measure temperature and pressure, or, for cogeneration units that calculate gross output based on steam characteristics, devices to measure steam flow rate, steam pressure, and steam temperature.

6.1.4 Do not calculate the PM emission rate for any unit or stack operating hour in which valid data are not obtained for PM concentration or for any parameter used in the PM emission rate calculations (*i.e.*, gross output, stack gas flow rate, stack temperature, stack pressure, stack gas moisture content, or diluent gas concentration, as applicable).

6.1.5 For the purposes of this appendix, part 75 substitute data values for stack gas flow rate, CO<sub>2</sub> concentration, O<sub>2</sub> concentration, and moisture content are not considered to be valid data.

6.1.6 Operating hours in which PM concentration is missing or invalid are hours of monitoring system downtime. The use of substitute data for PM concentration is not allowed.

6.1.7 You must exclude all data obtained during a boiler startup or shutdown operating hour (as defined in 40 CFR 63.10042) from the determination of the 30-boiler operating day rolling average PM emission rates.

**6.2 Calculation of PM Emission Rates.** Unless your PM CEMS is correlated to provide PM concentrations at standard conditions, you must use the calculation methods in sections 6.2.1 through 6.2.3 of this appendix to convert measured PM concentration values to units of the emission limit (lb/MMBtu or lb/MWh, as applicable).

6.2.1 PM concentrations must be at standard conditions in order to convert them to units of the emissions limit. If your PM CEMS measures PM concentrations at standard conditions, proceed to section 6.2.2 or 6.2.3, below (as applicable). However, if your PM CEMS measures PM concentrations in units of mg/acm or mg/acm at a specified temperature (*e.g.*, 160 °C), you must first use one of the following equations to convert the hourly PM concentration values from actual to standard conditions:

$$C_{std} = C_a \left( \frac{460 + T_s}{P_s} \right) \left( \frac{P_{std}}{460 + T_{std}} \right) \quad (\text{Eq. C-1})$$

or

$$C_{std} = C_a \left( \frac{460 + T_{CEMS}}{P_{CEMS}} \right) \left( \frac{P_{std}}{460 + T_{std}} \right) \quad (\text{Eq. C-2})$$

Where:

C<sub>std</sub> = PM concentration at standard conditions

C<sub>a</sub> = PM concentration at measurement conditions

T<sub>s</sub> = Stack Temperature ( °F)

T<sub>CEMS</sub> = CEMS Measurement Temperature ( °F)

P<sub>CEMS</sub> = CEMS Measurement Pressure (in. Hg)

P<sub>s</sub> = Stack Pressure (in. Hg)

$T_{std}$  = Standard Temperature (68 °F)

$P_{std}$  = Standard Pressure (29.92 in. Hg).

6.2.2 Heat Input-Based PM Emission Rates (Existing EGUs, Only). Calculate the hourly heat input-based PM emission rates (if applicable), in units of lb/MMBtu, according to sections 6.2.2.1 and 6.2.2.2 of this appendix.

6.2.2.1 You must select an appropriate emission rate equation from among Equations 19–1 through 19–9 in appendix A–7 to part 60 of this chapter to convert the hourly PM concentration values from section 6.2.1 of this appendix to units of lb/MMBtu. Note that the EPA test Method 19 equations require the pollutant concentration to be expressed in units of lb/scf; therefore, you must first multiply the PM concentration by  $6.24 \times 10^{-8}$  to convert it from mg/scm to lb/scf.

6.2.2.2 You must use the appropriate carbon-based or dry-basis F-factor in the emission rate equation that you have selected. You may either use an F-factor from Table 19–2 of EPA test Method 19 in appendix A–7 to part 60 of this chapter or from section 3.3.5 or section 3.3.6 of appendix F to part 75 of this chapter.

6.2.2.3 If the hourly average O<sub>2</sub> concentration is above 14.0% O<sub>2</sub> (19.0% for an IGCC) or the hourly average CO<sub>2</sub> concentration is below 5.0% CO<sub>2</sub> (1.0% for an IGCC), you may calculate the PM emission rate using the applicable diluent cap value (as defined in 40 CFR 63.10042 and specified in 40 CFR 63.10007(f)(1)), provided that the diluent gas monitor is operating and recording quality-assured data).

6.2.2.4 If your selected EPA test Method 19 equation requires a correction for the stack gas moisture content, you may either use quality-assured hourly data from a certified part 75 moisture monitoring system, a fuel-specific default moisture value from 40 CFR 75.11(b) of this chapter, or a site-specific default moisture value approved by the Administrator under section 75.66 of this chapter.

6.2.3 Gross Output-Based PM Emission Rates. For each unit or stack operating hour, if  $C_{std}$  is measured on a wet basis, you must use Equation C–3 to calculate the gross output-based PM emission rate (if applicable). Use Equation C–4 if  $C_{std}$  is measured on a dry basis:

$$E_{heo} = 6.24 \times 10^{-8} \left( \frac{C_{std} Q_s}{MW} \right) \quad (\text{Eq. C-3})$$

Where:

$E_{heo}$  = Hourly gross output-based PM emission rate (lb/MWh)

$C_{std}$  = PM concentration from section 6.2.1 (mg/scm), wet basis

$Q_s$  = Unadjusted stack gas volumetric flow rate (scfh, wet basis)

MW = Gross output (megawatts)

$6.24 \times 10^{-8}$  = Conversion factor

or

$$E_{heo} = 6.24 \times 10^{-8} \left( \frac{C_{std} Q_s}{MW} \right) (1 - B_{ws}) \quad (\text{Eq. C-4})$$

Where:

$E_{\text{heo}}$  = Hourly gross output-based PM emission rate (lb/MWh)

$C_{\text{std}}$  = PM concentration from section 6.2.1 (mg/scm), dry basis

$Q_s$  = Unadjusted stack gas volumetric flow rate (scfh, wet basis)

MW = Gross output (megawatts)

$B_{\text{ws}}$  = Proportion by volume of water vapor in the stack gas

$6.24 \times 10^{-8}$  = Conversion factor

6.2.4 You must calculate the 30–boiler operating day rolling average PM emission rates according to 40 CFR 63.10021(b).

## 7. Recordkeeping and Reporting

**7.1 Recordkeeping Provisions.** For the PM CEMS and the other necessary CMS and parameter measurement devices installed at each affected unit or common stack, you must maintain a file of all measurements, data, reports, and other information required by this appendix in a form suitable for inspection, for 5 years from the date of each record, in accordance with 40 CFR 63.10033. The file shall contain the applicable information in sections 7.1.1 through 7.1.11 of this appendix.

**7.1.1 Monitoring Plan Records.** For each EGU or group of EGUs monitored at a common stack, you must prepare and maintain a monitoring plan for the PM CEMS and the other CMS(s) needed to convert PM concentrations to units of the applicable emission standard.

**7.1.1.1 Updates.** If you make a replacement, modification, or change in a certified CEMS that is used to provide data under this appendix (including a change in the automated data acquisition and handling system (DAHS)) or if you make a change to the flue gas handling system and that replacement, modification, or change affects information reported in the monitoring plan (e.g., a change to a serial number for a component of a monitoring system), you shall update the monitoring plan.

**7.1.1.2 Contents of the Monitoring Plan.** For the PM CEMS, your monitoring plan shall contain the applicable information in sections 7.1.1.2.1 and 7.1.1.2.2 of this appendix. For required stack gas flow rate, diluent gas, and moisture monitoring systems, your monitoring plan shall include the applicable information required for those systems under 40 CFR 75.53 (g) and (h) of this chapter.

**7.1.1.2.1 Electronic.** Your electronic monitoring plan records must include the following information: Unit or stack ID number(s); unit information (type of unit, maximum rated heat input, fuel type(s), emission controls); monitoring location(s); the monitoring methodologies used; monitoring system information, including (as applicable): Unique system and component ID numbers; the make, model, and serial number of the monitoring equipment; the sample acquisition method; formulas used to calculate emissions; operating range and load information; monitor span and range information; units of measure of your PM concentrations (see section 3.2.2); and appropriate default values. Your electronic monitoring plan shall be evaluated and submitted using the ECMPS Client Tool provided by the Clean Air Markets Division (CAMD) in EPA's Office of Atmospheric Programs.

**7.1.1.2.2 Hard Copy.** You must keep records of the following items: Schematics and/or blueprints showing the location of the PM monitoring system(s) and test ports; data flow diagrams; test protocols; and miscellaneous technical justifications. The hard copy portion of the monitoring plan must also explain how the PM concentrations are measured and how they are converted to the units of the applicable emissions limit. The equation(s) used for the conversions must be documented. Electronic storage of the hard copy portion of the monitoring plan is permitted.

7.1.2 Operating Parameter Records. You must record the following information for each operating hour of each EGU and also for each group of EGUs utilizing a monitored common stack, to the extent that these data are needed to convert PM concentration data to the units of the emission standard. For non-operating hours, you must record only the items in sections 7.1.2.1 and 7.1.2.2 of this appendix. If you elect to or are required to comply with a gross output-based PM standard, for any hour in which there is gross output greater than zero, you must record the items in sections 7.1.2.1 through 7.1.2.3 and (if applicable) 7.1.2.5 of this appendix; however, if there is heat input to the unit(s) but no gross output (e.g., at unit startup), you must record the items in sections 7.1.2.1, 7.1.2.2, and, if applicable, section 7.1.2.5 of this appendix. If you elect to comply with a heat input-based PM standard, you must record only the items in sections 7.1.2.1, 7.1.2.2, 7.1.2.4, and, if applicable, section 7.1.2.5 of this appendix.

7.1.2.1 The date and hour;

7.1.2.2 The unit or stack operating time (rounded up to the nearest fraction of an hour (in equal increments that can range from 1 hundredth to 1 quarter of an hour, at your option));

7.1.2.3 The hourly gross output (rounded to nearest MWe);

7.1.2.4 If applicable, the  $F_c$  factor or dry-basis F-factor used to calculate the heat input-based PM emission rate; and

7.1.2.5 If applicable, a flag to indicate that the hour is an exempt startup or shutdown hour.

7.1.3 PM Concentration Records. For each affected unit or common stack using a PM CEMS, you must record the following information for each unit or stack operating hour:

7.1.3.1 The date and hour;

7.1.3.2 Monitoring system and component identification codes for the PM CEMS, as provided in the electronic monitoring plan, if your CEMS provides a quality-assured value of PM concentration for the hour;

7.1.3.3 The hourly PM concentration, in units of measure that correspond to your PM CEMS correlation curve, for each operating hour in which a quality-assured value is obtained. Record all PM concentrations with one leading non-zero digit and one decimal place, expressed in scientific notation. Use the following rounding convention: If the digit immediately following the first decimal place is 5 or greater, round the first decimal place upward (increase it by one); if the digit immediately following the first decimal place is 4 or less, leave the first decimal place unchanged.

7.1.3.4 A special code, indicating whether or not a quality-assured PM concentration is obtained for the hour; and

7.1.3.5 Monitor data availability for PM concentration, as a percentage of unit or stack operating hours calculated in the manner established for SO<sub>2</sub>, CO<sub>2</sub>, O<sub>2</sub> or moisture monitoring systems according to 40 CFR 75.32 of this chapter.

7.1.4 Stack Gas Volumetric Flow Rate Records.

7.1.4.1 When a gross output-based PM emissions limit must be met, in units of lb/MWh, you must obtain hourly measurements of stack gas volumetric flow rate during EGU operation, in order to convert PM concentrations to units of the standard.

7.1.4.2 When hourly measurements of stack gas flow rate are needed, you must keep hourly records of the flow rates and related information, as specified in 40 CFR 75.57(c)(2) of this chapter.

#### 7.1.5 Records of Diluent Gas (CO<sub>2</sub> or O<sub>2</sub>) Concentration.

7.1.5.1 When a heat input-based PM emission limit must be met, in units of lb/MMBtu, you must obtain hourly measurements of CO<sub>2</sub> or O<sub>2</sub> concentration during EGU operation, in order to convert PM concentrations to units of the standard.

7.1.5.2 When hourly measurements of diluent gas concentration are needed, you must keep hourly CO<sub>2</sub> or O<sub>2</sub> concentration records, as specified in 40 CFR 75.57(g) of this chapter.

#### 7.1.6 Records of Stack Gas Moisture Content.

7.1.6.1 When corrections for stack gas moisture content are needed to demonstrate compliance with the applicable PM emissions limit:

7.1.6.1.1 If you use a continuous moisture monitoring system, you must keep hourly records of the stack gas moisture content and related information, as specified in 40 CFR 75.57(c)(3) of this chapter.

7.1.6.1.2 If you use a fuel-specific default moisture value, you must represent it in the electronic monitoring plan required under section 7.1.1.2.1 of this appendix.

7.1.7 PM Emission Rate Records. For applicable PM emission limits in units of lb/MMBtu or lb/MWh, you must record the following information for each affected EGU or common stack:

7.1.7.1 The date and hour;

7.1.7.2 The hourly PM emissions rate (lb/MMBtu or lb/MWh, as applicable), calculated according to section 6.2.2 or 6.2.3 of this appendix, rounded to the same precision as the standard (*i.e.*, with one leading non-zero digit and one decimal place, expressed in scientific notation), expressed in scientific notation. Use the following rounding convention: If the digit immediately following the first decimal place is 5 or greater, round the first decimal place upward (increase it by one); if the digit immediately following the first decimal place is 4 or less, leave the first decimal place unchanged. You must calculate the PM emission rate only when valid values of PM concentration and all other required parameters required to convert PM concentration to the units of the standard are obtained for the hour;

7.1.7.3 An identification code for the formula used to derive the hourly PM emission rate from measurements of the PM concentration and other necessary parameters (*i.e.*, Equation C-3 or C-4 in section 6.2.3 of this appendix or the applicable EPA test Method 19 equation);

7.1.7.4 If applicable, indicate that the diluent cap has been used to calculate the PM emission rate; and

7.1.7.5 If applicable, indicate that the default electrical load (as defined in 40 CFR 63.10042) has been used to calculate the hourly PM emission rate.

7.1.7.6 Indicate that the PM emission rate was not calculated for the hour, if valid data are not obtained for PM concentration and/or any of the other parameters in the PM emission rate equation. For the purposes of this appendix, substitute data values for stack gas flow rate, CO<sub>2</sub> concentration, O<sub>2</sub> concentration, and moisture content reported under part 75 of this chapter are not considered to be valid data. However, when the gross output (as defined in 40 CFR 63.10042) is reported for an operating hour with zero output, the default electrical load value is treated as quality-assured data.

7.1.8 Other Parametric Data. If your PM CEMS measures PM concentrations at actual conditions, you must keep records of the temperatures and pressures used in Equation C-1 or C-2 to convert the measured hourly PM concentrations to standard conditions.

7.1.9 Certification, Recertification, and Quality Assurance Test Records. For any PM CEMS used to provide data under this subpart, you must record the following certification, recertification, and quality assurance information:



7.1.9.1 The test dates and times, reference values, monitor responses, monitor full scale value, and calculated results for the required 7-day drift tests and for the required daily zero and upscale calibration drift tests;

7.1.9.2 The test dates and times and results (pass or fail) of all daily system optics checks and daily sample volume checks of the PM CEMS (as applicable);

7.1.9.3 The test dates and times, reference values, monitor responses, and calculated results for all required quarterly ACAs;

7.1.9.4 The test dates and times, reference values, monitor responses, and calculated results for all required quarterly SVAs of extractive PM CEMS;

7.1.9.5 The test dates and times, reference method readings and corresponding PM CEMS responses (including the units of measure), and the calculated results for all PM CEMS correlation tests, RRAs and RCAs. For the correlation tests, you must indicate which model is used (*i.e.*, linear, logarithmic, exponential, polynomial, or power) and record the correlation equation. For the RRAs and RCAs, the reference method readings and PM CEMS responses must be reported in the same units of measure as the PM CEMS correlation;

7.1.9.6 The cycle time and sample delay time for PM CEMS that operate in batch sampling mode; and

7.1.9.7 Supporting information for all required PM CEMS correlation tests, RRAs, and RCAs, including records of all raw reference method and monitoring system data, the results of sample analyses to substantiate the reported test results, as well as records of sampling equipment calibrations, reference monitor calibrations, and analytical equipment calibrations.

7.1.10 For stack gas flow rate, diluent gas, and moisture monitoring systems, you must keep records of all certification, recertification, diagnostic, and on-going quality-assurance tests of these systems, as specified in 40 CFR 75.59(a) of this chapter.

7.1.11 For each temperature measurement device (*e.g.*, resistance temperature detector or thermocouple) and pressure measurement device used to convert measured PM concentrations to standard conditions according to Equation C-1 or C-2, you must keep records of all calibrations and other checks performed to ensure that accurate data are obtained.

## **7.2 Reporting Requirements.**

7.2.1 General Reporting Provisions. You must comply with the following requirements for reporting PM emissions from each affected EGU (or group of EGUs monitored at a common stack) under this subpart:

7.2.1.1 Notifications, in accordance with section 7.2.2 of this appendix;

7.2.1.2 Monitoring plan reporting, in accordance with section 7.2.3 of this appendix;

7.2.1.3 Certification, recertification, and quality assurance test submittals, in accordance with section 7.2.4 of this appendix; and

7.2.1.4 Electronic quarterly emissions report submittals, in accordance with section 7.2.5 of this appendix.

7.2.2 Notifications. You must provide notifications for each affected unit (or group of units monitored at a common stack) under this subpart in accordance with 40 CFR 63.10030.

7.2.3 Monitoring Plan Reporting. For each affected unit (or group of units monitored at a common stack) under this subpart using PM CEMS to measure PM emissions, you must make electronic and hard copy monitoring plan submittals as follows:

7.2.3.1 For an EGU that begins reporting hourly PM concentrations on January 1, 2024, with a previously certified PM CEMS, submit the monitoring plan information in section 7.1.1.2 of this appendix prior to or concurrent with the first required quarterly emissions report. For a new EGU, or for an EGU switching to continuous monitoring of PM emissions after having implemented another allowable compliance option under this subpart, submit the information in section 7.1.1.2 of this appendix at least 21 days prior to the start of initial certification testing of the PM CEMS. Also submit the monitoring plan information in 40 CFR 75.53(g) pertaining to any required flow rate, diluent gas, and moisture monitoring systems within the applicable time frame specified in this section, if the required records are not already in place.

7.2.3.2 Whenever an update of the monitoring plan is required, as provided in section 7.1.1.1 of this appendix, you must submit the updated information either prior to or concurrent with the relevant quarterly electronic emissions report.

7.2.3.3 All electronic monitoring plan submittals and updates shall be made to the Administrator using the ECMPS Client Tool. Hard copy portions of the monitoring plan shall be submitted to the appropriate delegated authority.

7.2.4 Certification, Recertification, and Quality-Assurance Test Reporting. Except for daily quality assurance tests of the required monitoring systems (*i.e.*, calibration error or drift tests, sample volume checks, system optics checks, and flow monitor interference checks), you must submit the results of all required certification, recertification, and quality-assurance tests described in sections 7.1.9.1 through 7.1.9.6 and 7.1.10 of this appendix electronically (except for test results previously submitted, *e.g.*, under the Acid Rain Program), using the ECMPS Client Tool. Submit the results of the quality assurance test (*i.e.*, RCA or RRA) or, if applicable, a new PM CEMS correlation test, either prior to or concurrent with the relevant quarterly electronic emissions report. If this is not possible, you have up to 60 days after the test completion date to submit the test results; in this case, you may claim provisional status for the emissions data affected by the quality assurance test or correlation, starting from the date and hour in which the test was completed and continuing until the date and hour in which the test results are submitted. For an RRA or RCA, if the applicable audit specifications are met, the status of the emissions data in the relevant time period changes from provisional to quality-assured, and no further action is required. For a successful correlation test, apply the correlation equation retrospectively to the raw data to change the provisional status of the data to quality-assured, and resubmit the affected emissions report(s). However, if the applicable performance specifications are not met, the provisional data must be invalidated, and resubmission of the affected quarterly emission report(s) is required. For a failed RRA or RCA, you must take corrective actions and proceed according to the applicable requirements found in sections 10.5 through 10.7 of Procedure 2 until a successful quality assurance test report is submitted. If a correlation test is unsuccessful, you may not report quality-assured data from the PM CEMS until the results of a subsequent correlation test show that the specifications in section 13.0 of PS 11 are met.

#### 7.2.5 Quarterly Reports.

7.2.5.1 For each affected EGU (or group of EGUs monitored at a common stack), the owner or operator must use the ECMPS Client Tool to submit electronic quarterly emissions reports to the Administrator, in an XML format specified by the Administrator, starting with a report for the later of:

7.2.5.1.1 The first calendar quarter of 2024; or

7.2.5.1.2 The calendar quarter in which the initial PM CEMS correlation test is completed.

7.2.5.2 You must submit the electronic reports within 30 days following the end of each calendar quarter, except for EGUs that have been placed in long-term cold storage (as defined in section 72.2 of this chapter).

7.2.5.3 Each of your electronic quarterly reports shall include the following information:

7.2.5.3.1 The date of report generation;

7.2.5.3.2 Facility identification information;

7.2.5.3.3 The information in sections 7.1.2 through 7.1.7 of this appendix that is applicable to your PM emission measurement methodology; and

7.2.5.3.4 The results of all daily quality assurance assessments, *i.e.*, calibration drift checks and (if applicable) sample volume checks of the PM CEMS, calibration error tests of the other continuous monitoring systems that are used to convert PM concentration to units of the standard, and (if applicable) flow monitor interference checks.

7.2.5.4 Compliance Certification. Based on a reasonable inquiry of those persons with primary responsibility for ensuring that all PM emissions from the affected unit(s) under this subpart have been correctly and fully monitored, the owner or operator must submit a compliance certification in support of each electronic quarterly emissions monitoring report. The compliance certification shall include a statement by a responsible official with that official's name, title, and signature, certifying that, to the best of his or her knowledge, the report is true, accurate, and complete.

[85 FR 55769, Sept. 9, 2020]

## Appendix D to Subpart UUUUU of Part 63—PM CPMS Monitoring Provisions

### 1. General Provisions

1.1 **Applicability.** These monitoring provisions apply to the continuous monitoring of the output from a PM CPMS, for the purpose of assessing continuous compliance with an applicable emissions limit in Table 1 or Table 2 to this subpart.

1.2 **Summary of the Method.** The output from an instrument capable of continuously measuring PM concentration is continuously recorded, either in milliamps, PM concentration, or other units of measure. An operating limit for the PM CPMS is established initially, based on data recorded by the monitoring system during a performance stack test. The performance test is repeated annually, and the operating limit is reassessed. In-between successive performance tests, the output from the PM CPMS serves as an indicator of continuous compliance with the applicable emissions limit.

### 2. Continuous Monitoring of the PM CPMS Output

2.1 **System Design and Performance Criteria.** The PM CPMS must meet the design and performance criteria specified in 40 CFR 63.10010(h)(1)(i) through (iii) and 40 CFR 63.10023(b)(2)(iii) and (iv). In addition, an automated DAHS is required to record the output from the PM CPMS and to generate the quarterly electronic data reports required under section 3.2.4 of this appendix.

2.2 **Installation Requirements.** Install the PM CPMS at an appropriate location in the stack or duct, in accordance with 40 CFR 63.10010(a).

#### 2.3 Determination of Operating Limits.

2.3.1 In accordance with 40 CFR 63.10007(a)(3), 40 CFR 63.10011(b), 40 CFR 63.10023(a), and Table 6 to this subpart, you must determine an initial site-specific operating limit for your PM CPMS, using data recorded by the monitoring system during a performance stack test that demonstrates compliance with one of the following emissions limits in Table 1 or Table 2 to this subpart: Filterable PM; total non-Hg HAP metals; total HAP metals including Hg (liquid oil-fired units, only); individual non-Hg HAP metals; or individual HAP metals including Hg (liquid oil-fired units, only).

2.3.2 In accordance with 40 CFR 63.10005(d)(2)(i), you must perform the initial stack test no later than the applicable date in 40 CFR 63.9984(f), and according to 40 CFR 63.10005(d)(2)(iii) and 63.10006(a), the performance test must be repeated annually to document compliance with the emissions limit and to reassess the operating limit.

2.3.3 Calculate the operating limits according to 40 CFR 63.10023(b)(1) for existing units, and 40 CFR 63.10023(b)(2) for new units.

#### 2.4 **Data Reduction and Compliance Assessment.**

2.4.1 Reduce the output from the PM CPMS to hourly averages, in accordance with 40 CFR 63.8(g)(2) and (5).

2.4.2 To determine continuous compliance with the operating limit, you must calculate 30-boiler operating day rolling average values of the output from the PM CPMS, in accordance with 40 CFR 63.10010(h)(3) through (6), 40 CFR 63.10021(c), and Table 7 to this subpart.

2.4.3 In accordance with 40 CFR 63.10005(d)(2)(ii), 40 CFR 63.10022(a)(2), and Table 4 to this subpart, the 30-boiler operating day rolling average PM CPMS output must be maintained at or below the operating limit. However, if exceedances of the operating limit should occur, you must follow the applicable procedures in 40 CFR 63.10021(c)(1) and (2).

### 3. RECORDKEEPING AND REPORTING.

3.1 **Recordkeeping Provisions.** You must keep the applicable records required under 40 CFR 63.10032(b) and (c) for your PM CPMS. In addition, you must maintain a file of all measurements, data, reports, and other information required by this appendix in a form suitable for inspection, for 5 years from the date of each record, in accordance with 40 CFR 63.10033.

#### 3.1.1 Monitoring Plan Records.

3.1.1.1 You must develop and maintain a site-specific monitoring plan for your PM CPMS, in accordance with 63.10000(d).

3.1.1.2 In addition to the site-specific monitoring plan required under 40 CFR 63.10000(d), you must use the ECMPS Client Tool to prepare and maintain an electronic monitoring plan for your PM CPMS.

3.1.1.2.1 Contents of the Electronic Monitoring Plan. The electronic monitoring plan records must include the unit or stack ID number(s), monitoring location(s), the monitoring methodology used (*i.e.*, PM CPMS), the current operating limit of the PM CPMS (including the units of measure), unique system and component ID numbers, the make, model, and serial number of the PM CPMS, the analytical principle of the monitoring system, and monitor span and range information.

3.1.1.2.2 Electronic Monitoring Plan Updates. If you replace or make a change to a PM CPMS that is used to provide data under this subpart (including a change in the automated DAHS) and the replacement or change affects information reported in the electronic monitoring plan (*e.g.*, changes to the make, model and serial number when a PM CPMS is replaced), you must update the monitoring plan.

3.1.2 Operating Parameter Records. You must record the following information for each operating hour of each affected unit and for each group of units utilizing a common stack. For non-operating hours, record only the items in sections 3.1.2.1 and 3.1.2.2 of this appendix.

3.1.2.1 The date and hour;

3.1.2.2 The unit or stack operating time (rounded up to the nearest fraction of an hour (in equal increments that can range from 1 hundredth to 1 quarter of an hour, at the option of the owner or operator); and

3.1.2.3 If applicable, a flag to indicate that the hour is an exempt startup or shutdown hour.

3.1.3 PM CPMS Output Records. For each affected unit or common stack using a PM CPMS, you must record the following information for each unit or stack operating hour:

3.1.3.1 The date and hour;

3.1.3.2 Monitoring system and component identification codes for the PM CPMS, as provided in the electronic monitoring plan, for each operating hour in which the monitoring system is not out-of-control and a valid value of the output parameter is obtained;

3.1.3.3 The hourly average output from the PM CPMS, for each operating hour in which the monitoring system is not out-of-control and a valid value of the output parameter is obtained, either in milliamps, PM concentration, or other units of measure, as applicable;

3.1.3.4 A special code for each operating hour in which the PM CPMS is out-of-control and a valid value of the output parameter is not obtained; and

3.1.3.5 Percent monitor data availability for the PM CPMS, calculated in the manner established for SO<sub>2</sub>, CO<sub>2</sub>, O<sub>2</sub> or moisture monitoring systems according to section 75.32 of this chapter.

3.1.4 Records of PM CPMS Audits and Out-of-Control Periods. In accordance with 40 CFR 63.10010(h)(7), you must record, and make available upon request, the results of PM CPMS performance audits, as well as the dates of PM CPMS out-of-control periods and the corrective actions taken to return the system to normal operation.

### **3.2 Reporting Requirements.**

3.2.1 General Reporting Provisions. You must comply with the following requirements for reporting PM CPMS data from each affected EGU (or group of EGUs monitored at a common stack) under this subpart:

3.2.1.1 Notifications, in accordance with section 3.2.2 of this appendix;

3.2.1.2 Monitoring plan reporting, in accordance with section 3.2.3 of this appendix;

3.2.1.3 Report submittals, in accordance with sections 3.2.4 and 3.2.5 of this appendix.

3.2.2 Notifications. You must provide notifications for the affected unit (or group of units monitored at a common stack) in accordance with 40 CFR 63.10030.

3.2.3 Monitoring Plan Reporting. For each affected unit (or group of units monitored at a common stack) under this subpart using a PM CPMS you must make monitoring plan submittals as follows:

3.2.3.1 For units using the PM CPMS compliance option prior to January 1, 2024, submit the electronic monitoring plan information in section 3.1.1.2.1 of this appendix prior to or concurrent with the first required electronic quarterly report. For units switching to the PM CPMS methodology on or after January 1, 2024, submit the electronic monitoring plan no later than 21 days prior to the date on which the PM test is performed to establish the initial operating limit.

3.2.3.2 Whenever an update of the electronic monitoring plan is required, as provided in section 3.1.1.2.2 of this appendix, the updated information must be submitted either prior to or concurrent with the relevant quarterly electronic emissions report.

3.2.3.3 All electronic monitoring plan submittals and updates shall be made to the Administrator using the ECMPMS Client Tool.

3.2.3.4 In accordance with 40 CFR 63.10000(d), you must submit the site-specific monitoring plan described in section 3.1.1.1 of this appendix to the Administrator, if requested.

3.2.4 Electronic Quarterly Reports.

3.2.4.1 For each affected EGU (or group of EGUs monitored at a common stack) that is subject to the provisions of this appendix, reporting of hourly responses from the PM CPMS will begin either with the first operating hour in the third quarter of 2023 or the first operating hour after completion of the initial stack test that establishes the operating limit, whichever is later. The owner or operator must then use the ECMPS Client Tool to submit electronic quarterly reports to the Administrator, in an XML format specified by the Administrator, starting with a report for the later of:

3.2.4.1.1 The first calendar quarter of 2024; or

3.2.4.1.2 The calendar quarter in which the initial operating limit for the PM CPMS is established.

3.2.4.2 The electronic quarterly reports must be submitted within 30 days following the end of each calendar quarter, except for units that have been placed in long-term cold storage (as defined in section 72.2 of this chapter).

3.2.4.3 Each electronic quarterly report shall include the following information:

3.2.4.3.1 The date of report generation;

3.2.4.3.2 Facility identification information; and

3.2.4.3.3 The information in sections 3.1.2 and 3.1.3 of this appendix.

3.2.4.4 Compliance Certification. Based on a reasonable inquiry of those persons with primary responsibility for ensuring that the output from the PM CPMS has been correctly and fully monitored, the owner or operator shall submit a compliance certification in support of each electronic quarterly report. The compliance certification shall include a statement by a responsible official with that official's name, title, and signature, certifying that, to the best of his or her knowledge, the report is true, accurate, and complete.

3.2.5 Performance Stack Test Results. You must use the ECMPS Client Tool to report the results of all performance stack tests conducted to document compliance with the applicable emissions limit in Table 1 or Table 2 to this subpart, as follows:

3.2.5.1 Report a summary of each test electronically, in XML format, in the relevant quarterly compliance report under 40 CFR 63.10031(g); and

3.2.5.2 Provide a complete stack test report as a PDF file, in accordance with 40 CFR 63.10031(f) or (h), as applicable.

[85 FR 55774, Sept. 9, 2020]

#### **Appendix E to Subpart UUUUU of Part 63—Data Elements**

1.0 You must record the electronic data elements in this appendix that apply to your compliance strategy under this subpart. The applicable data elements in sections 2 through 13 of this appendix must be reported in the quarterly compliance reports required under 40 CFR 63.10031(g), in an XML format prescribed by the Administrator, starting with a report that covers the first quarter of 2024. For stack tests used to demonstrate compliance, RATAs, PM CEMS correlations, RRAs and RCAs that are completed on and after January 1, 2024, the applicable data elements in sections 17 through 30 of this appendix must be reported in an XML format prescribed by the Administrator, and the information in section 31 of this appendix must be reported in as one or more PDF files.

2.0 **MATS Compliance Report Root Data Elements.** You must record the following data elements and include them in each quarterly compliance report:

2.1 Energy Information Administration's Office of Regulatory Information Systems (ORIS) Code;

2.2 Facility Name;

2.3 Facility Registry Identifier;

2.4 Title 40 Part;

2.5 Applicable Subpart;

2.6 Calendar Year;

2.7 Calendar Quarter; and

2.8 Submission Comment (optional)

3.0 **Performance Stack Test Summary.** If you elect to demonstrate compliance using periodic performance stack testing (including 30-boiler operating day Hg LEE tests), record the following data elements for each test:

3.1 Parameter

3.2 Test Location ID;

3.3 Test Number;

3.4 Test Begin Date, Hour, and Minute;

3.5 Test End Date, Hour, and Minute;

3.6 Timing of Test (either performed on-schedule according to 40 CFR 63.10006(f), or was late);

3.7 Averaging Plan Indicator;

3.8 Averaging Group ID (if applicable);

3.9 EPA Test Method Code;

3.10 Emission Limit, Including Units of Measure;

3.11 Average Pollutant Emission Rate;

3.12 LEE Indicator;

3.13 LEE Basis (if applicable); and

3.14 Submission Comment (optional)

4.0 **Operating limit Data (PM CPMS, only):**

4.1 Parameter Type;

4.2 Operating Limit; and

4.3 Units of Measure.

5.0 **Performance Test Run Data.** For each run of the performance stack test, record the following data elements:

5.1 Run Number

5.2 Run Begin Date, Hour, and Minute;

5.3 Run End Date, Hour, and Minute;

5.4 Pollutant Concentration and Units of Measure;

5.5 Emission Rate;

5.6 EPA Test Method 19 Equation (if applicable);

5.7 Total Sampling Time; and

5.8 Total Sample Volume.

6.0 **Conversion Parameters.** For the parameters that are used to convert the pollutant concentration to units of the emission standard (including, as applicable, CO<sub>2</sub> or O<sub>2</sub> concentration, stack gas flow rate, stack gas moisture content, F-factors, and gross output), record:

6.1 Parameter Type;

6.2 Parameter Source; and

6.3 Parameter Value, Including Units of Measure.

7.0 **Quality Assurance Parameters:** For key parameters that are used to quality-assure the reference method data (including, as applicable, filter temperature, percent isokinetic, leak check results, percent breakthrough, percent spike recovery, and relative deviation), record:

7.1 Parameter Type;

7.2 Parameter Value; and

7.3 Pass/Fail Status.

8.0 **Averaging Group Configuration.** If a particular EGU or common stack is included in an averaging plan, record the following data elements:

8.1 Parameter Being Averaged;

8.2 Averaging Group ID; and

8.3 Unit or Common Stack ID.

9.0 **Compliance Averages.** If you elect to (or are required to) demonstrate compliance using continuous monitoring system(s) on a 30-boiler operating day rolling average basis (or on a 30- or 90-group boiler operating day rolling WAER basis, if your monitored EGU or common stack is in an averaging plan), you must record the following data elements for each average emission rate (or, for units in an averaging plan, for each WAER):

9.1 Unit or Common Stack ID;



9.2 Averaging Group ID (if applicable);

9.3 Parameter Being Averaged;

9.4 Date;

9.5 Average Type;

9.6 Units of Measure; and

9.7 Average Value.

9.8 Comment Field.

10.0 **Unit Information.** You must record the following data elements for each EGU:

10.1 Unit ID;

10.2 Date of Last Tune-up; and

10.3 **Emergency Bypass Information.** If your coal-fired EGU, solid oil-derived fuel-fired EGU, or IGCC is equipped with a main stack and a bypass stack (or bypass duct) configuration, and has qualified to use the LEE compliance option, you must report the following emergency bypass information annually, in the compliance report for the fourth calendar quarter of the year:

10.3.1 The number of emergency bypass hours for the year, as a percentage of the EGU's annual operating hours;

10.3.2 A description of each emergency bypass event during the year, including the cause and corrective actions taken;

10.3.3 An explanation of how clean fuels were burned to the maximum extent possible during each emergency bypass event;

10.3.4 An estimate of the emissions released during each emergency bypass event. You must also show whether LEE status has been retained or lost, based on the emissions estimate and the results of the previous LEE retest; and

10.3.5 If there were no emergency bypass events during the year, a statement to that effect.

11.0 **Fuel Usage Information.** If subject to an emissions limit, record the following monthly fuel usage information:

11.1 Calendar Month;

11.2 Each Type of Fuel Used During the Calendar Month in the Quarter;

11.3 Quantity of Each Type of Fuel Combusted in Each Calendar Month in the Quarter, with Units of Measure;

11.4 New Fuel Type Indicator (if applicable); and

11.5 Date of Performance Test Using the New Fuel (if applicable).

12.0 **Malfunction Information (if applicable):** If there was a malfunction of the process equipment or control equipment during the reporting period that caused (or may have caused) an exceedance of an emissions or operating limit, record:

12.1 Event Begin Date and Hour (if known);

12.2 Event End Date and Hour;

12.3 Malfunction Description; and

12.4 Corrective Action.

13.0 **Deviations and Monitoring Downtime.** If there were any deviations or monitoring downtime during the reporting period, record:

13.1 Unit, Common Stack, or Averaging Group ID;

13.2 The nature of the deviation, as either:

13.2.1 Emission limit exceeded;

13.2.2 Operating limit exceeded;

13.2.3 Work practice standard not met;

13.2.4 Testing requirement not met;

13.2.5 Monitoring requirement not met;

13.2.6 Monitoring downtime incurred; or

13.2.7 Other requirement not met.

13.3 A description of the deviation, or monitoring downtime, as follows:

13.3.1 For a performance stack test or a 30- (or 90-) boiler operating day rolling average that exceeds an emissions or operating limit, record the parameter (e.g., HCl, Hg, PM), the limit that was exceeded, and either the date of the non-complying performance test or the beginning and ending dates of the non-complying rolling average;

13.3.2 If an unmonitored bypass stack was used during the reporting period, record the total number of hours of bypass stack usage;

13.3.3 For periods where valid monitoring data are not reported during the reporting period, record the monitored parameter, the total source operating time (hours), and the total number of hours of monitoring deviation or downtime and other information, as indicated, for:

13.3.3.1 Monitoring system malfunctions/repairs (deviation and downtime);

13.3.3.2 Out-of-control periods/repairs (deviation and downtime);

13.3.3.3 Non-monitoring equipment malfunctions (downtime);

13.3.3.4 QA/QC activities (excluding zero and span checks) (downtime);

13.3.3.5 Routine maintenance (downtime);

13.3.3.6 Other known causes (downtime); and

13.3.3.7 Unknown causes (downtime).

13.3.4 If a performance stack test was due within the quarter but was not done, record the parameter (e.g., HCl, PM), the test deadline, and a statement that the test was not done as required;

13.3.5 For a late performance stack test conducted during the quarter, record the parameter, the test deadline, and the number of days that elapsed between the test deadline and the test completion date.

13.4 Record any corrective actions taken in response to the deviation.

13.5 If there were no deviations and/or no monitoring downtime during the quarter, record a statement to that effect.

**14.0 Reference Method Data Elements.** For each of the following tests that is completed on and after January 1, 2024, you must record and report the applicable electronic data elements in sections 17 through 29 of this appendix, pertaining to the reference method(s) used for the test (see section 16 of this appendix).

14.1 Each quarterly, annual, or triennial stack test used to demonstrate compliance (including 30- (or 90-) boiler operating day Hg LEE tests and PM tests used to set operating limits for PM CPMS);

14.2 Each RATA of your Hg, HCl, HF, or SO<sub>2</sub> CEMS or each RATA of your Hg sorbent trap monitoring system; and

14.3 Each correlation test, RRA and each RCA of your PM CEMS.

15.0 You must report the applicable data elements for each test described in section 14 of this appendix in an XML format prescribed by the Administrator.

15.1 For each stack test completed during a particular calendar quarter and contained in the quarterly compliance report, you must submit along with the quarterly compliance report, the data elements in sections 17 and 18 of this appendix (which are common to all tests) and the applicable data elements in sections 19 through 31 of this appendix associated with the reference method(s) used.

15.2 For each RATA, PM CEMS correlation, RRA, or RCA, when you use the ECMPMS Client Tool to report the test results as required under appendix A, B, or C to this subpart or, for SO<sub>2</sub> RATAs under part 75 of this chapter, you must submit along with the test results, the data elements in sections 17 and 18 of this appendix and, for each test run, the data elements in sections 19 through 30 of this appendix that are associated with the reference method(s) used.

15.3 For each stack test, RATA, PM CEMS correlation, RRA, and RCA, you must also provide the information described in section 31 of this appendix as a PDF file, either along with the quarterly compliance report (for stack tests) or together with the test results reported under appendix A, B, or C to this subpart or part 75 of this chapter (for RATAs, RRAs, RCAs, or PM CEMS correlations).

**16.0 Applicable Reference Methods.** One or more of the following EPA reference methods is needed for the tests described in sections 14.1 through 14.3 of this appendix: Method 1, 2, 3A, 4, 5, 5D, 6C, 26, 26A, 29, and/or 30B.

16.1 Application of EPA test Methods 1 and 2. If you use periodic stack testing to comply with an *output-based* emissions limit, you must determine the stack gas flow rate during each performance test run in which EPA test Method 5, 5D, 26, 26A, 29, or 30B is used, in order to convert the measured pollutant concentration to units of the standard. For EPA test Methods 5, 5D, 26A and 29, which require isokinetic sampling, the delta-P readings made with the pitot tube and manometer at the EPA test Method 1 traverse points, taken together with

measurements of stack gas temperature, pressure, diluent gas concentration (from a separate EPA test Method 3A or 3B test) and moisture, provide the necessary data for the EPA test Method 2 flow rate calculations. Note that even if you elect to comply with a *heat input-based* standard, when EPA test Method 5, 5D, 26A, or 29 is used, you must still use EPA test Method 2 to determine the average stack gas velocity ( $v_s$ ), which is needed for the percent isokinetic calculation. The EPA test Methods 26 and 30B do not require isokinetic sampling; therefore, when either of these methods is used, if the stack gas flow rate is needed to comply with the applicable *output-based* emissions limit, you must make a separate EPA test Method 2 determination during each test run.

16.2 Application of EPA test Method 3A. If you elect to perform periodic stack testing to comply with a *heat input-based* emissions limit, a separate measurement of the diluent gas ( $\text{CO}_2$  or  $\text{O}_2$ ) concentration is required for each test run in which EPA test Method 5, 5D, 26, 26A, 29, or 30B is used, in order to convert the measured pollutant concentration to units of the standard. The EPA test Method 3A is the preferred  $\text{CO}_2$  or  $\text{O}_2$  test method, although EPA test Method 3B may be used instead. Diluent gas measurements are also needed for stack gas molecular weight determinations when using EPA test Method 2.

16.3 Application of EPA test Method 4. For performance stack tests, depending on which equation is used to convert pollutant concentration to units of the standard, measurement of the stack gas moisture content, using EPA test Method 4, may also be required for each test run. The EPA test Method 4 moisture data are also needed for the EPA test Method 2 calculations (to determine the molecular weight of the gas) and for the RATA of an Hg CEMS that measures on a wet basis, when EPA test Method 30B is used. Other applications that require EPA test Method 4 moisture determinations include: RATAs of an  $\text{SO}_2$  monitor, when the reference method and CEMS data are measured on a different moisture basis (wet or dry); conversion of wet-basis pollutant concentrations to the units of a *heat input-based* emissions limit when certain EPA test Method 19 equations are used (e.g., Eq. 19-3, 19-4, or 19-8); and stack gas molecular weight determinations. When EPA test Method 5, 5D, 26A, or 29 is used for the performance test, the EPA test Method 4 moisture determination may be made by using the water collected in the impingers together with data from the dry gas meter; alternatively, a separate EPA test Method 4 determination may be made. However, when EPA test Method 26 or 30B is used, EPA test Method 4 must be performed separately.

16.4 Applications of EPA test Methods 5 and 5D. The EPA test Method 5 (or, if applicable 5D) must be used for the following applications: To demonstrate compliance with a filterable PM emissions limit; for PM tests used to set operating limits for PM CPMS; and for the initial correlations, RRAs and RCAs of a PM CEMS.

16.5 Applications of EPA test Method 6C. If you elect to monitor  $\text{SO}_2$  emissions from your coal-fired EGU as a surrogate for HCl, the  $\text{SO}_2$  CEMS must be installed, certified, operated, and maintained according to 40 CFR part 75. Part 75 allows the use of EPA test Methods 6, 6A, 6B, and 6C for the required RATAs of the  $\text{SO}_2$  monitor. However, in practice, only instrumental EPA test Method 6C is used.

16.6 Applications of EPA test Methods 26 and 26A. The EPA test Method 26A may be used for quarterly HCl or HF stack testing, or for the RATA of an HCl or HF CEMS. The EPA test Method 26 may be used for quarterly HCl or HF stack testing; however, for the RATAs of an HCl monitor that is following PS 18 and Procedure 6 in appendices B and F to part 60 of this chapter, EPA test Method 26 may only be used if approved upon request.

16.7 Applications of EPA test Method 29. The EPA test Method 29 may be used for periodic performance stack tests to determine compliance with individual or total HAP metals emissions limits. For coal-fired EGUs, the total HAP emissions limits exclude Hg.

16.8 Applications of EPA test Method 30B. The EPA test Method 30B is used for 30- (or 90-) boiler operating day Hg LEE tests and RATAs of Hg CEMS and sorbent trap monitoring systems, and it may be used for quarterly Hg stack testing (oil-fired EGUs, only).

**17.0 Facility and Test Company Information.** In accordance with 40 CFR 63.7(e)(3), a test is defined as three or more runs of one or more EPA Reference Method(s) conducted to measure the amount of a specific regulated pollutant, pollutants, or surrogates being emitted from a particular EGU (or group of EGUs that share a common stack), and to satisfy requirements of this subpart. On or after January 1, 2024, you must report the data elements in sections 17 and 18, each time that you complete a required performance stack test, RATA, PM CEMS correlation, RRA, or RCA at the affected EGU(s), using EPA test Method 5, 5B, 5D, 6C, 26, 26A, 29, or 30B. You must also report the applicable data elements in sections 19 through 25 of this appendix for each test. If any

separate, corresponding EPA test Method 2, 3A, or 4 test is conducted in order to convert a pollutant concentration to the units of the applicable emission standard given in Table 1 or Table 2 of this subpart or to convert pollutant concentration from wet to dry basis (or vice-versa), you must also report the applicable data elements in sections 26 through 31 of this appendix.

The applicable data elements in sections 17 through 31 of this appendix must be submitted separately, in XML format, along with the quarterly Compliance Report (for stack tests) or along with the electronic test results submitted to the ECMPS Client Tool (for CMS performance evaluations). The Electronic Reporting Tool (ERT) or an equivalent schema can be utilized to create this XML file. *Note:* Ideally, for all of the tests completed at a given facility in a particular calendar quarter, the applicable data elements in sections 17 through 31 of this appendix should be submitted together in one XML file. However, as shown in Table 8 to this subpart, the timelines for submitting stack test results and CMS performance evaluations are not identical. Therefore, for calendar quarters in which both types of tests are completed, it may not be possible to submit the applicable data elements for all of those tests in a single XML file; separate submittals may be necessary to meet the applicable reporting deadlines.

17.1 Part;

17.2 Subpart;

17.3 ORIS Code;

17.4 Facility Name;

17.5 Facility Address;

17.6 Facility City;

17.7 Facility County;

17.8 Facility State;

17.9 Facility Zip Code;

17.10 Facility Point of Contact;

17.11 Facility Contact Phone Number;

17.12 Facility Contact Email;

17.13 EPA Facility Registration System Number;

17.14 Source Classification Code;

17.15 State Facility ID;

17.16 Project Number;

17.17 Name of Test Company;

17.18 Test Company Address;

17.19 Test Company City;

17.20 Test Company State;

17.21 Test Company Zip Code;

17.22 Test Company Point of Contact;

17.23 Test Company Contact Phone Number;

17.24 Test Company Contact Email; and

17.25 Test Comment (optional, PM CPMS operating limits, if applicable).

**18.0 Source Information Data Elements.** You must report the following data elements, as applicable, for each source for which at least one test is included in the XML file:

18.1 Source ID (sampling location);

18.2 Stack (duct) Diameter (circular stack) (in.);

18.3 Equivalent Diameter (rectangular duct or stack) (in.);

18.4 Area of Stack;

18.5 Control Device Code; and

18.6 Control Device Description.

**19.0 Run-Level and Lab Data Elements for EPA test Methods 5, 5B, 5D, 26A, and 29.** You must report the appropriate Source ID (*i.e.*, Data Element 18.1) and the following data elements, as applicable, for each run of each performance stack test, PM CEMS correlation test, RATA, RRA, or RCA conducted using isokinetic EPA test Method 5, 5B, 5D, or 26A. If your EGU is oil-fired and you use EPA test Method 26A to conduct stack tests for both HCl and HF, you must report these data elements separately for each pollutant. When you use EPA test Method 29 to measure the individual HAP metals, total filterable HAP metals and total HAP metals, report only the run-level data elements (19.1, 19.3 through 19.30, and 19.38 through 19.41), and the point-level and lab data elements in sections 20 and 21 of this appendix:

19.1 Test Number;

19.2 Pollutant Name;

19.3 EPA Test Method;

19.4 Run Number;

19.5 Corresponding Reference Method(s), if applicable;

19.6 Corresponding Reference Method(s) Run Number, if applicable;

19.7 Number of Traverse Points;

19.8 Run Begin Date;

19.9 Run Start Time (clock time start);

19.10 Run End Date;

- 19.11 Run End Time (clock time end);
- 19.12 Barometric Pressure;
- 19.13 Static Pressure;
- 19.14 Cumulative Elapsed Sampling Time;
- 19.15 Percent O<sub>2</sub>;
- 19.16 Percent CO<sub>2</sub>;
- 19.17 Pitot Tube ID;
- 19.18 Pitot Tube Calibration Coefficient;
- 19.19 Nozzle Calibration Diameter;
- 19.20 F-Factor (F<sub>d</sub>, F<sub>w</sub>, or F<sub>c</sub>);
- 19.21 Calibration Coefficient of Dry Gas Meter (Y);
- 19.22 Total Volume of Liquid Collected in Impingers and Silica Gel;
- 19.23 Percent Moisture—Actual;
- 19.24 Dry Molecular Weight of Stack Gas;
- 19.25 Wet Molecular Weight of Stack Gas;
- 19.26 Initial Reading of Dry Gas Meter Volume (dcf);
- 19.27 Final Reading of Dry Gas Meter Volume (dcf);
- 19.28 Stack Gas Velocity—fps;
- 19.29 Stack Gas Flow Rate—dscfm;
- 19.30 Type of Fuel;
- 19.31 Pollutant Mass Collected (value);
- 19.32 Pollutant Mass Unit of Measure;
- 19.33 Detection Limit Flag;
- 19.34 Pollutant Concentration;
- 19.35 Pollutant Concentration Unit of Measure;
- 19.36 Pollutant Emission Rate;
- 19.37 Pollutant Emission Rate Units of Measure (in units of the standard);

19.38 Compliance Limit Basis (heat input or electrical output);

19.39 Heat Input or Electrical Output Unit of Measure;

19.40 Process Parameter (value);

19.41 Process Parameter Unit of Measure;

19.42 Converted Concentration for PM CEMS only; and

19.43 Converted Concentration Units (units of correlation for PM CEMS).

**20.0 Point-Level Data Elements for EPA test Methods 5, 5B, 5D, 26A, & 29.** To link the point-level data with the run data in the xml schema, you must report the Source ID (*i.e.*, Data Element 18.1), EPA Test Method (Data Element 19.3), Run Number (Data Element 19.4), and Run Begin Date (Data Element 19.8) with the following point-level data elements for each run of each performance stack test, PM CEMS correlation test, RATA, RRA, or RCA conducted using isokinetic EPA test Method 5, 5B, 5D, 26A, or 29. Note that these data elements are required for all EPA test Method 29 applications, whether the method is being used to measure the total or individual HAP metals concentrations:

20.1 Traverse Point ID;

20.2 Stack Temperature;

20.3 Differential Pressure Reading ( $\Delta P$ );

20.4 Orifice Pressure Reading ( $\Delta H$ );

20.5 Dry Gas Meter Inlet Temperature;

20.6 Dry Gas Meter Outlet Temperature; and

20.7 Filter Temperature.

**21.0 Laboratory Results for EPA test Methods 29 Total or Individual Multiple HAP Metals.** If you use EPA test Method 29 and elect to comply with the total or individual HAP metals standards, you must report run-level data elements 19.1 through 19.34 in Section 19, and the point-level data elements in Section 20. To link the laboratory data with the run data in the xml schema, you must report the Source ID (*i.e.*, Data Element 18.1), EPA Test Method (Data Element 19.3), Run Number (Data Element 19.4), and Run Begin Date (Data Element 19.8) with the results of the laboratory analyses. Regardless of whether you elect to comply with the total HAP metals standard or the individual HAP metals standard, you must report the front half catch, the back half catch, and the sum of the front and back half catches collected with EPA test Method 29 for each individual HAP metal and for the total HAP metals. The list of individual HAP metals is Antimony, Arsenic, Beryllium, Cadmium, Chromium, Cobalt, Lead, Manganese, Nickel, Selenium, and Mercury (if applicable). You must also calculate and report the pollutant emission rates(s) in relation to the standard(s) with which you have elected to comply and the units specified in Table 5 as follows:

21.1 Each Individual HAP metal total mass collected:

21.1.1 Pollutant Name;

21.1.2 Pollutant Mass Collected;

21.1.3 Pollutant Mass Units of Measure; and



21.1.4 Detection Limit Flag.

21.2 Each Individual HAP metal Front Half:

21.2.1 Pollutant Name;

21.2.2 Pollutant Mass Collected;

21.2.3 Pollutant Mass Units of Measure; and

21.2.4 Detection Limit Flag.

21.3 Each Individual HAP metal Back Half:

21.3.1 Pollutant Name;

21.3.2 Pollutant Mass Collected;

21.3.3 Pollutant Mass Units of Measure; and

21.3.4 Detection Limit Flag.

21.4 Each Individual HAP metal concentration:

21.4.1 Pollutant Name;

21.4.2 Pollutant Concentration; and

21.4.3 Pollutant Concentration Units of Measure.

21.5 Each Individual HAP metal emission rate in units of the standard:

21.5.1 Pollutant Name;

21.5.2 Pollutant Emission Rate; and

21.5.3 Pollutant Emission Rate Units of Measure.

21.6 Each Individual HAP metal emission rate in units of lbs/MMBTU or lbs/MW (per Table 5):

21.6.1 Pollutant Name;

21.6.2 Pollutant Emission Rate; and

21.6.3 Pollutant Emission Rate Units of Measure.

21.7 Total Filterable HAP metals mass collected:

21.7.1 Pollutant Name;

21.7.2 Pollutant Mass Collected;

21.7.3 Pollutant Mass Units of Measure; and

21.7.4 Detection Limit Flag.

21.8 Total Filterable HAP metals concentration:

21.8.1 Pollutant Name;

21.8.2 Pollutant Concentration; and

21.8.3 Pollutant Concentration Units of Measure.

21.9 Total Filterable HAP metals in units of lbs/MMBtu or lbs/MW (per Table 5):

21.9.1 Pollutant Name;

21.9.2 Pollutant Emission Rate; and

21.9.3 Pollutant Emission Rate Units of Measure.

21.10 Total HAP metals mass collected:

21.10.1 Pollutant Name;

21.10.2 Pollutant Mass Collected;

21.10.3 Pollutant Mass Units of Measure; and

21.10.4 Detection Limit Flag.

21.11 Total HAP metals concentration

21.11.1 Pollutant Name;

21.11.2 Pollutant Concentration; and

21.11.3 Pollutant Concentration Units of Measure.

21.12 Total HAP metals Emission Rate in Units of the Standard:

21.12.1 Pollutant Name;

21.12.2 Pollutant Emission Rate; and

21.12.3 Pollutant Emission Rate Units of Measure.

21.13 Total HAP metals Emission Rate in lbs/MMBtu or lbs/MW (per Table 5):

21.13.1 Pollutant Name;

21.13.2 Pollutant Emission Rate; and

21.13.3 Pollutant Emission Rate Units of Measure.

**22.0 Run-Level and Lab Data Elements for EPA test Method 26.** If you use EPA test Method 26, you must report the Source ID (*i.e.*, Data Element 18.1) and the following run-level data elements for each test run. If your EGU is oil-fired and you use EPA test Method 26 to conduct stack tests for both HCl and HF, you must report these data elements separately for each pollutant:

22.1 Test Number;

22.2 Pollutant Name;

22.3 EPA Test Method;

22.4 Run Number;

22.5 Corresponding Reference Method(s), if applicable;

22.6 Corresponding Reference Method(s) Run Number, if applicable;

22.7 Number of Traverse Points;

22.8 Run Begin Date;

22.9 Run Start Time (clock start time);

22.10 Run End Date;

22.11 Run End Time (clock end time);

22.12 Barometric Pressure;

22.13 Cumulative Elapsed Sampling Time;

22.14 Calibration Coefficient of Dry Gas Meter (Y);

22.15 Initial Reading of Dry Gas Meter Volume (dcf);

22.16 Final Reading of Dry Gas Meter Volume (dcf);

22.17 Percent O<sub>2</sub>;

22.18 Percent CO<sub>2</sub>;

22.19 Type of Fuel;

22.20 F-Factor (F<sub>d</sub>, F<sub>w</sub>, or F<sub>c</sub>);

22.21 Pollutant Mass Collected (value);

22.22 Pollutant Mass Units of Measure;

22.23 Detection Limit Flag;

22.24 Pollutant Concentration;

22.25 Pollutant Concentration Unit of Measure;

22.26 Compliance Limit Basis (heat input or electrical output);

22.27 Heat Input or Electrical Output Unit of Measure;

22.28 Process Parameter (value);

22.29 Process Parameter Unit of Measure;

22.30 Pollutant Emission Rate; and

22.31 Pollutant Emission Rate Units of Measure (in the units of the standard).

**23.0 Point-Level Data Elements for EPA test Method 26.** To link the point-level data in this section with the run-level data in the XML schema, you must report the Source ID (*i.e.*, Data Element 18.1), EPA Test Method (Data Element 22.3), Run Number (Data Element 22.4), and Run Begin Date (Data Element 22.8) from section 22 and the following point-level data elements for each run of each EPA test Method 26 test:

23.1 Traverse Point ID;

23.2 Filter Temperature; and

23.3 Dry Gas Meter Temperature.

**24.0 Run-Level Data for EPA test Method 30B.** You must report Source ID (*i.e.* Data Element 18.1) and the following run-level data elements for each EPA test Method 30B test run:

24.1 Test Number;

24.2 Pollutant Name;

24.3 EPA Test Method;

24.4 Run Number;

24.5 Corresponding Reference Method(s), if applicable;

24.6 Corresponding Reference Method(s) Run Number, if applicable;

24.7 Number of Traverse Points;

24.8 Run Begin Date;

24.9 Run Start Time (clock time start);

24.10 Run End Date;

24.11 Run End Time (clock time end);

24.12 Barometric Pressure;

24.13 Percent O<sub>2</sub>;

- 24.14 Percent CO<sub>2</sub>;
- 24.15 Cumulative Elapsed Sampling Time;
- 24.16 Calibration Coefficient of Dry Gas Meter Box A (Y);
- 24.17 Initial Reading of Dry Gas Meter Volume (A);
- 24.18 Final Reading of Dry Gas Meter Volume (A);
- 24.19 Calibration Coefficient of Dry Gas Meter Box B (Y);
- 24.20 Initial Reading of Dry Gas Meter Volume (B);
- 24.21 Final Reading of Dry Gas Meter Volume (B);
- 24.22 Gas Sample Volume Units of Measure;
- 24.23 Post-Run Leak Rate (A);
- 24.24 Post-Run Leak Check Vacuum (A);
- 24.25 Post-Run Leak Rate (B);
- 24.26 Post-Run Leak Check Vacuum (B);
- 24.27 Sorbent Trap ID (A);
- 24.28 Pollutant Mass Collected, Section 1 (A);
- 24.29 Pollutant Mass Collected, Section 2 (A);
- 24.30 Mass of Spike on Sorbent Trap A;
- 24.31 Total Pollutant Mass Trap A;
- 24.32 Sorbent Trap ID (B);
- 24.33 Pollutant Mass Collected, Section 1 (B);
- 24.34 Pollutant Mass Collected, Section 2 (B);
- 24.35 Mass of Spike on Sorbent Trap B;
- 24.36 Total Pollutant Mass Trap B;
- 24.37 Pollutant Mass Units of Measure;
- 24.38 Pollutant Average Concentration;
- 24.39 Pollutant Concentration Units of Measure;
- 24.40 Method Detection Limit;

24.41 Percent Spike Recovery;

24.42 Type of Fuel;

24.43 F-Factor ( $F_d$ ,  $F_w$ , or  $F_c$ );

24.44 Compliance Limit Basis (heat input or electrical output);

24.45 Heat Input or Electrical Output Unit of Measure;

24.46 Process Parameter (value);

24.47 Process Parameter Unit of Measure;

24.48 Pollutant Emission Rate; and

24.49 Pollutant Emission Rate Unit of Measure (in the units of the standard).

**25.0 Point-Level Data Elements for EPA test Method 30B.** You must report the Source ID (*i.e.*, Data Element 18.1), EPA Test Method (Data Element 24.3), Run Number (Data Element 24.4), and Run Begin Date (Data Element 24.8) and the following point-level data elements for each run of each EPA test Method 30B test:

25.1 Traverse Point ID;

25.2 Dry Gas Meter Temperature (A);

25.3 Sample Flow Rate (A) (L/min);

25.4 Dry Gas Meter Temperature (B); and

25.5 Sample Flow Rate (B) (L/min).

**26.0 Pre-Run Data Elements for EPA test Methods 3A and 6C.** You must report the Source ID (*i.e.*, Data Element 18.1) and the following pre-run data elements for each SO<sub>2</sub> RATA using instrumental EPA test Method 6C, and for each instrumental EPA test Method 3A O<sub>2</sub> or CO<sub>2</sub> test that is performed to convert a pollutant concentration to the units of measure of the applicable emission unit of standard in Table 1 or 2 of this subpart:

26.1 Test Number;

26.2 EPA Test Method;

26.3 Calibration Gas Cylinder Analyte;

26.4 Cylinder Gas Units of Measure;

26.5 Date of Calibration;

26.6 Calibration Low-Level Gas Cylinder ID;

26.7 Calibration Low-Level Gas Concentration;

26.8 Calibration Low-Level Cylinder Expiration Date;

26.9 Calibration Mid-Level Gas Cylinder ID;

- 26.10 Calibration Mid-Level Gas Concentration;
- 26.11 Calibration Mid-Level Cylinder Expiration Date;
- 26.12 Calibration High-Level Gas Cylinder ID;
- 26.13 Calibration Span (High-Level) Gas Concentration;
- 26.14 Calibration High-Level Cylinder Expiration Date;
- 26.15 Low-Level Gas Response;
- 26.16 Low-Level Calibration Error;
- 26.17 Low-Level Alternate Performance Specification (APS) Flag;
- 26.18 Mid-Level Gas Response;
- 26.19 Mid-Level Calibration Error;
- 26.20 Mid-Level APS Flag;
- 26.21 High-Level Gas Response;
- 26.22 High-Level Calibration Error; and
- 26.23 High-Level APS Flag.

**27.0 Run-Level Data Elements for EPA test Methods 3A and 6C.** You must report the Source ID (*i.e.*, Data Element 18.1) and following run-level data elements for each run of each SO<sub>2</sub> RATA using instrumental EPA test Method 6C, and for each run of each corresponding instrumental EPA test Method 3A test that is performed to convert a pollutant concentration to the applicable emission unit of standard in Table 1 or 2 of this subpart:

- 27.1 Test Number;
- 27.2 Pollutant or Analyte Name;
- 27.3 EPA Test Method;
- 27.4 Run Number;
- 27.5 Corresponding Reference Method(s), if applicable;
- 27.6 Corresponding Reference Method(s) Run Number(s), if applicable;
- 27.7 Number of Traverse Points;
- 27.8 Run Begin Date;
- 27.9 Run Start Time (clock time start);
- 27.10 Run End Date;

- 27.11 Run End Time (clock time end);
- 27.12 Cumulative Elapsed Sampling Time;
- 27.13 Upscale (mid or high) Gas Level;
- 27.14 Pre-Run Low-Level Response;
- 27.15 Pre-Run Low-Level System Bias;
- 27.16 Pre-Run Low-Level Bias APS Flag;
- 27.17 Pre-Run Upscale (mid or high) Response;
- 27.18 Pre-Run Upscale (mid or high) System Bias;
- 27.19 Pre-Run Upscale (mid or high) Bias APS Flag;
- 27.20 Post-Run Low-Level Response;
- 27.21 Post-Run Low-Level System Bias;
- 27.22 Post-Run Low-Level Bias APS Flag;
- 27.23 Post-Run Low-Level Drift;
- 27.24 Post-Run Low-Level Drift APS Flag;
- 27.25 Post-Run Upscale (mid or high) Response;
- 27.26 Post-Run Upscale (mid or high) System Bias;
- 27.27 Post-Run Upscale (mid or high) System Bias APS Flag;
- 27.28 Post-Run Upscale (mid or high) Drift;
- 27.29 Post-Run Upscale (mid or high) Drift APS Flag;
- 27.30 Unadjusted Raw Emissions Average Concentration;
- 27.31 Calculated Average Concentration, Adjusted for Bias ( $C_{\text{gas}}$ );
- 27.32 Concentration Units of Measure (Dry or wet);
- 27.33 Type of Fuel;
- 27.34 Process Parameter (value); and
- 27.35 Process Parameter Units of Measure.



**28.0 Run-Level Data Elements for EPA test Method 2.** When you make a separate determination of the stack gas flow rate using EPA test Method 2 separately, corresponding to a pollutant reference method test, *i.e.*, when data from the pollutant reference method cannot determine the stack gas flow rate, you must report the Source ID (*i.e.*, Data Element 18.1) and following run-level data elements for each EPA test Method 2 test run:

28.1 Test Number;

28.2 EPA Test Method;

28.3 Run Number;

28.4 Number of Traverse Points;

28.5 Run Begin Date;

28.6 Run Start Time (clock time start);

28.7 Run End Date;

28.8 Run End Time (clock time end);

28.9 Pitot Tube ID;

28.10 Pitot Tube Calibration Coefficient;

28.11 Barometric Pressure;

28.12 Static Pressure;

28.13 Percent O<sub>2</sub>;

28.14 Percent CO<sub>2</sub>;

28.15 Percent Moisture—actual;

28.16 Dry Molecular Weight of Stack Gas;

28.17 Wet Molecular Weight of Stack Gas;

28.18 Stack Gas Velocity—fps; and

28.19 Stack Gas Flow Rate—dscfm.

**29.0 Point-Level Data Elements for EPA test Method 2.** For each run of each separate EPA test Method 2 test, you must report the Source ID (*i.e.*, Data Element 18.1), EPA Test Method (Data Element 28.2), Run Number (Data Element 28.3), and Run Begin Date (Data Element 28.5) and the following point-level data elements:

29.1 Traverse Point ID;

29.2 Stack Temperature; and

29.3 Differential Pressure Reading ( $\Delta P$ ).

**30.0 Run-Level Data Elements for EPA test Method 4.** When you make a separate EPA test Method 4 determination of the stack gas moisture content corresponding to a pollutant reference method test, *i.e.*, when data from the pollutant reference method cannot determine the moisture content, you must report the Source ID (*i.e.*, Data Element 18.1) and the following run-level data elements for each EPA test Method 4 test run:

30.1 Test Number;

30.2 EPA Test Method;

30.3 Run Number;

30.4 Number of Traverse Points;

30.5 Run Begin Date;

30.6 Run Start Time (clock time start);

30.7 Run End Date;

30.8 Run End Time (clock time end);

30.9 Barometric Pressure;

30.10 Calibration Coefficient of Dry Gas Meter (Y);

30.11 Volume of Water Collected in Impingers and Silica Gel;

30.12 Percent Moisture-actual;

30.13 Initial Reading of Dry Gas Meter Volume (dcf);

30.14 Final Reading of Dry Gas Meter Volume (dcf); and

30.15 Dry Gas Meter Temperature (average).

**31.0 Other Information for Each Test or Test Series.** You must provide each test included in the XML data file described in this appendix with supporting documentation, in a PDF file submitted concurrently with the XML file, such that all the data required to be reported by 40 CFR 63.7(g) are provided. That supporting data include but are not limited to diagrams showing the location of the test site and the sampling points, laboratory report(s) including analytical calibrations, calibrations of source sampling equipment, calibration gas cylinder certificates, raw instrumental data, field data sheets, quality assurance data (*e.g.* field recovery spikes) and any required audit results and stack testers' credentials (if applicable). The applicable data elements in 40 CFR 63.10031(f)(6)(i) through (xii) of this section must be entered into ECMPs with each PDF submittal; the test number(s) (see 40 CFR 63.10031(f)(6)(xi)) must be included. The test number(s) must match the test number(s) in sections 19 through 31 of this appendix (as applicable).

[85 FR 55775, Sept. 9, 2020]

## Attachment F

### Part 70 Operating Permit No: 165-47094-00001

[Downloaded from the eCFR on December 7, 2022]

#### Title 40: Protection of Environment

#### PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

#### Subpart DDDDD—National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

**Source:** 76 FR 15664, Mar. 21, 2011, unless otherwise noted.

#### What This Subpart Covers

##### § 63.7480 What is the purpose of this subpart?

This subpart establishes national emission limitations and work practice standards for hazardous air pollutants (HAP) emitted from industrial, commercial, and institutional boilers and process heaters located at major sources of HAP. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and work practice standards.

##### § 63.7485 Am I subject to this subpart?

You are subject to this subpart if you own or operate an industrial, commercial, or institutional boiler or process heater as defined in § 63.7575 that is located at, or is part of, a major source of HAP, except as specified in § 63.7491. For purposes of this subpart, a major source of HAP is as defined in § 63.2, except that for oil and natural gas production facilities, a major source of HAP is as defined in § 63.7575.

[78 FR 7162, Jan. 31, 2013]

##### § 63.7490 What is the affected source of this subpart?

(a) This subpart applies to new, reconstructed, and existing affected sources as described in paragraphs (a)(1) and (2) of this section.

(1) The affected source of this subpart is the collection at a major source of all existing industrial, commercial, and institutional boilers and process heaters within a subcategory as defined in § 63.7575.

(2) The affected source of this subpart is each new or reconstructed industrial, commercial, or institutional boiler or process heater, as defined in § 63.7575, located at a major source.

(b) A boiler or process heater is new if you commence construction of the boiler or process heater after June 4, 2010, and you meet the applicability criteria at the time you commence construction.

(c) A boiler or process heater is reconstructed if you meet the reconstruction criteria as defined in § 63.2, you commence reconstruction after June 4, 2010, and you meet the applicability criteria at the time you commence reconstruction.

(d) A boiler or process heater is existing if it is not new or reconstructed.

(e) An existing electric utility steam generating unit (EGU) that meets the applicability requirements of this subpart after the effective date of this final rule due to a change (e.g., fuel switch) is considered to be an existing source under this subpart.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7162, Jan. 31, 2013]

**§ 63.7491 Are any boilers or process heaters not subject to this subpart?**

The types of boilers and process heaters listed in paragraphs (a) through (n) of this section are not subject to this subpart.

(a) An electric utility steam generating unit (EGU) covered by subpart UUUUU of this part or a natural gas-fired EGU as defined in subpart UUUUU of this part firing at least 85 percent natural gas on an annual heat input basis.

(b) A recovery boiler or furnace covered by subpart MM of this part.

(c) A boiler or process heater that is used specifically for research and development, including test steam boilers used to provide steam for testing the propulsion systems on military vessels. This does not include units that provide heat or steam to a process at a research and development facility.

(d) A hot water heater as defined in this subpart.

(e) A refining kettle covered by subpart X of this part.

(f) An ethylene cracking furnace covered by subpart YY of this part.

(g) Blast furnace stoves as described in EPA-453/R-01-005 (incorporated by reference, see § 63.14).

(h) Any boiler or process heater that is part of the affected source subject to another subpart of this part, such as boilers and process heaters used as control devices to comply with subparts JJJ, OOO, PPP, and U of this part.

(i) Any boiler or process heater that is used as a control device to comply with another subpart of this part, or part 60, part 61, or part 65 of this chapter provided that at least 50 percent of the average annual heat input during any 3 consecutive calendar years to the boiler or process heater is provided by regulated gas streams that are subject to another standard.

(j) Temporary boilers and process heaters as defined in this subpart.

(k) Blast furnace gas fuel-fired boilers and process heaters as defined in this subpart.

(l) Any boiler or process heater specifically listed as an affected source in any standard(s) established under section 129 of the Clean Air Act.

(m) A unit that burns hazardous waste covered by Subpart EEE of this part. A unit that is exempt from Subpart EEE as specified in § 63.1200(b) is not covered by Subpart EEE.

(n) Residential boilers as defined in this subpart.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7162, Jan. 31, 2013; 80 FR 72806, Nov. 20, 2015]

**§ 63.7495 When do I have to comply with this subpart?**

- (a) If you have a new or reconstructed boiler or process heater, you must comply with this subpart by April 1, 2013, or upon startup of your boiler or process heater, whichever is later.
- (b) If you have an existing boiler or process heater, you must comply with this subpart no later than January 31, 2016, except as provided in § 63.6(i).
- (c) If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, paragraphs (c)(1) and (2) of this section apply to you.
- (1) Any new or reconstructed boiler or process heater at the existing source must be in compliance with this subpart upon startup.
- (2) Any existing boiler or process heater at the existing source must be in compliance with this subpart within 3 years after the source becomes a major source.
- (d) You must meet the notification requirements in § 63.7545 according to the schedule in § 63.7545 and in subpart A of this part. Some of the notifications must be submitted before you are required to comply with the emission limits and work practice standards in this subpart.
- (e) If you own or operate an industrial, commercial, or institutional boiler or process heater and would be subject to this subpart except for the exemption in § 63.7491(l) for commercial and industrial solid waste incineration units covered by part 60, subpart CCCC or subpart DDDD, and you cease combusting solid waste, you must be in compliance with this subpart and are no longer subject to part 60, subparts CCCC or DDDD beginning on the effective date of the switch as identified under the provisions of § 60.2145(a)(2) and (3) or § 60.2710(a)(2) and (3).
- (f) If you own or operate an existing EGU that becomes subject to this subpart after January 31, 2016, you must be in compliance with the applicable existing source provisions of this subpart on the effective date such unit becomes subject to this subpart.
- (g) If you own or operate an existing industrial, commercial, or institutional boiler or process heater and would be subject to this subpart except for an exemption in § 63.7491(i) that becomes subject to this subpart after January 31, 2013, you must be in compliance with the applicable existing source provisions of this subpart within 3 years after such unit becomes subject to this subpart.
- (h) If you own or operate an existing industrial, commercial, or institutional boiler or process heater and have switched fuels or made a physical change to the boiler or process heater that resulted in the applicability of a different subcategory after the compliance date of this subpart, you must be in compliance with the applicable existing source provisions of this subpart on the effective date of the fuel switch or physical change.
- (i) If you own or operate a new industrial, commercial, or institutional boiler or process heater and have switched fuels or made a physical change to the boiler or process heater that resulted in the applicability of a different subcategory, you must be in compliance with the applicable new source provisions of this subpart on the effective date of the fuel switch or physical change.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7162, Jan. 31, 2013; 80 FR 72807, Nov. 20, 2015]

**Emission Limitations and Work Practice Standards**

**§ 63.7499 What are the subcategories of boilers and process heaters?**

The subcategories of boilers and process heaters, as defined in § 63.7575 are:

- (a) Pulverized coal/solid fossil fuel units.

- (b) Stokers designed to burn coal/solid fossil fuel.
- (c) Fluidized bed units designed to burn coal/solid fossil fuel.
- (d) Stokers/sloped grate/other units designed to burn kiln dried biomass/bio-based solid.
- (e) Fluidized bed units designed to burn biomass/bio-based solid.
- (f) Suspension burners designed to burn biomass/bio-based solid.
- (g) Fuel cells designed to burn biomass/bio-based solid.
- (h) Hybrid suspension/grate burners designed to burn wet biomass/bio-based solid.
- (i) Stokers/sloped grate/other units designed to burn wet biomass/bio-based solid.
- (j) Dutch ovens/pile burners designed to burn biomass/bio-based solid.
- (k) Units designed to burn liquid fuel that are non-continental units.
- (l) Units designed to burn gas 1 fuels.
- (m) Units designed to burn gas 2 (other) gases.
- (n) Metal process furnaces.
- (o) Limited-use boilers and process heaters.
- (p) Units designed to burn solid fuel.
- (q) Units designed to burn liquid fuel.
- (r) Units designed to burn coal/solid fossil fuel.
- (s) Fluidized bed units with an integrated fluidized bed heat exchanger designed to burn coal/solid fossil fuel.
- (t) Units designed to burn heavy liquid fuel.
- (u) Units designed to burn light liquid fuel.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7163, Jan. 31, 2013]

**§ 63.7500 What emission limitations, work practice standards, and operating limits must I meet?**

(a) You must meet the requirements in paragraphs (a)(1) through (3) of this section, except as provided in paragraphs (b) through (e) of this section. You must meet these requirements at all times the affected unit is operating, except as provided in paragraph (f) of this section.

(1) You must meet each emission limit and work practice standard in Tables 1 through 3 and 11 through 15 to this subpart that applies to your boiler or process heater, for each boiler or process heater at your source, except as provided under § 63.7522. The output-based emission limits, in units of pounds per million Btu of steam output, in Table 1 or 2 to this subpart are an alternative applicable only to boilers and process heaters that generate either steam, cogenerate steam with electricity, or both. The output-based emission limits, in units of pounds per megawatt-hour, in Table 1 or 2 to this subpart are an alternative applicable only to boilers that

generate only electricity. Boilers that perform multiple functions (cogeneration and electricity generation) or supply steam to common headers would calculate a total steam energy output using Equation 1 of § 63.7575 to demonstrate compliance with the output-based emission limits, in units of pounds per million Btu of steam output, in Table 1 or 2 to this subpart. If you operate a new boiler or process heater, you can choose to comply with alternative limits as discussed in paragraphs (a)(1)(i) through (iv) of this section, but on or after October 6, 2025, you must comply with the emission limits in Table 1 to this subpart. If you operate an existing boiler or process heater, you can choose to comply with alternative limits as discussed in paragraph (a)(1)(v) of this section, but on or after October 6, 2025 you must comply with the emission limits in Table 2 to this subpart.

(i) If your boiler or process heater commenced construction or reconstruction after June 4, 2010, and before May 20, 2011, you may comply with the emission limits in Table 11 or 14 to this subpart until January 31, 2016.

(ii) If your boiler or process heater commenced construction or reconstruction on or after May 20, 2011, and before December 23, 2011, you may comply with the emission limits in Table 12 or 14 to this subpart until January 31, 2016.

(iii) If your boiler or process heater commenced construction or reconstruction on or after December 23, 2011, and before April 1, 2013, you may comply with the emission limits in Table 13 or 14 to this subpart until January 31, 2016.

(iv) If you operate a new boiler or process heater, you must comply with either the emission limits in Table 1 to this subpart or the emission limits in Table 14 to this subpart until you must comply with the emission limits in Table 1.

(v) If you operate an existing boiler or process heater, you must comply with either the emission limits in Table 2 to this subpart or the emission limits in Table 15 to this subpart until you must comply with the emission limits in Table 2.

(2) You must meet each operating limit in Table 4 to this subpart that applies to your boiler or process heater. If you use a control device or combination of control devices not covered in Table 4 to this subpart, or you wish to establish and monitor an alternative operating limit or an alternative monitoring parameter, you must apply to the EPA Administrator for approval of alternative monitoring under § 63.8(f).

(3) At all times, you must operate and maintain any affected source (as defined in § 63.7490), including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator that may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

(b) As provided in § 63.6(g), EPA may approve use of an alternative to the work practice standards in this section.

(c) Limited-use boilers and process heaters must complete a tune-up every 5 years as specified in § 63.7540. They are not subject to the emission limits in Tables 1 and 2 or Tables 11 through 15 to this subpart, the annual tune-up, or the energy assessment requirements in Table 3 to this subpart, or the operating limits in Table 4 to this subpart.

(d) Boilers and process heaters with a heat input capacity of less than or equal to 5 million Btu per hour in the units designed to burn gas 2 (other) fuels subcategory or units designed to burn light liquid fuels subcategory must complete a tune-up every 5 years as specified in § 63.7540.

(e) Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity of less than or equal to 5 million Btu per hour must complete a tune-up every 5 years as specified in § 63.7540. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity greater than 5 million Btu per hour and less than 10 million Btu per hour must complete a tune-up every 2 years as specified in § 63.7540. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory are not subject to the emission limits in Tables 1 and 2 or Tables 11 through 15 to this subpart, or the operating limits in Table 4 to this subpart.

(f) These standards apply at all times the affected unit is operating, except during periods of startup and shutdown during which time you must comply only with items 5 and 6 of Table 3 to this subpart.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7163, Jan. 31, 2013; 80 FR 72807, Nov. 20, 2015; 87 FR 60840, Oct. 6, 2022]

## § 63.7501 [Reserved]

### General Compliance Requirements

#### § 63.7505 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limits, work practice standards, and operating limits in this subpart. These emission and operating limits apply to you at all times the affected unit is operating except for the periods noted in § 63.7500(f).

(b) [Reserved]

(c) You must demonstrate compliance with all applicable emission limits using performance stack testing, fuel analysis, or continuous monitoring systems (CMS), including a continuous emission monitoring system (CEMS), continuous opacity monitoring system (COMS), continuous parameter monitoring system (CPMS), or particulate matter continuous parameter monitoring system (PM CPMS), where applicable. You may demonstrate compliance with the applicable emission limit for hydrogen chloride (HCl), mercury, or total selected metals (TSM) using fuel analysis if the emission rate calculated according to § 63.7530(c) is less than the applicable emission limit. For gaseous fuels, you may not use fuel analyses to comply with the TSM alternative standard or the HCl standard. Otherwise, you must demonstrate compliance for HCl, mercury, or TSM using performance stack testing, if subject to an applicable emission limit listed in Table 1 or 2 or Tables 11 through 15 to this subpart.

(d) If you demonstrate compliance with any applicable emission limit through performance testing and subsequent compliance with operating limits through the use of CPMS, or with a CEMS or COMS, you must develop a site-specific monitoring plan according to the requirements in paragraphs (d)(1) through (4) of this section for the use of any CEMS, COMS, or CPMS. This requirement also applies to you if you petition the EPA Administrator for alternative monitoring parameters under § 63.8(f).

(1) For each CMS required in this section (including CEMS, COMS, or CPMS), you must develop, and submit to the Administrator for approval upon request, a site-specific monitoring plan that addresses design, data collection, and the quality assurance and quality control elements outlined in § 63.8(d) and the elements described in paragraphs (d)(1)(i) through (iii) of this section. You must submit this site-specific monitoring plan, if requested, at least 60 days before your initial performance evaluation of your CMS. This requirement to develop and submit a site specific monitoring plan does not apply to affected sources with existing CEMS or COMS operated according to the performance specifications under appendix B to part 60 of this chapter and that meet the requirements of § 63.7525. Using the process described in § 63.8(f)(4), you may request approval of alternative monitoring system quality assurance and quality control procedures in place of those specified in this paragraph and, if approved, include the alternatives in your site-specific monitoring plan.

(i) Installation of the CMS sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (e.g., on or downstream of the last control device);

(ii) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems; and

(iii) Performance evaluation procedures and acceptance criteria (e.g., calibrations, accuracy audits, analytical drift).



(2) In your site-specific monitoring plan, you must also address paragraphs (d)(2)(i) through (iii) of this section.

(i) Ongoing operation and maintenance procedures in accordance with the general requirements of § 63.8(c)(1)(ii), (c)(3), and (c)(4)(ii);

(ii) Ongoing data quality assurance procedures in accordance with the general requirements of § 63.8(d); and

(iii) Ongoing recordkeeping and reporting procedures in accordance with the general requirements of § 63.10(c) (as applicable in Table 10 to this subpart), (e)(1), and (e)(2)(i).

(3) You must conduct a performance evaluation of each CMS in accordance with your site-specific monitoring plan.

(4) You must operate and maintain the CMS in continuous operation according to the site-specific monitoring plan.

(e) If you have an applicable emission limit, and you choose to comply using definition (2) of “startup” in § 63.7575, you must develop and implement a written startup and shutdown plan (SSP) according to the requirements in Table 3 to this subpart. The SSP must be maintained onsite and available upon request for public inspection.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7164, Jan. 31, 2013; 80 FR 72807, Nov. 20, 2015; 87 FR 60841, Oct. 6, 2022]

### **Testing, Fuel Analyses, and Initial Compliance Requirements**

#### **§ 63.7510 What are my initial compliance requirements and by what date must I conduct them?**

(a) For each boiler or process heater that is required or that you elect to demonstrate compliance with any of the applicable emission limits in Table 1 or 2 or Tables 11 through 15 to this subpart through performance (stack) testing, your initial compliance requirements include all the following:

(1) Conduct performance tests according to § 63.7520 and Table 5 to this subpart.

(2) Conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to § 63.7521 and Table 6 to this subpart, except as specified in paragraphs (a)(2)(i) through (iii) of this section.

(i) For each boiler or process heater that burns a single type of fuel, you are not required to conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to § 63.7521 and Table 6 to this subpart. For purposes of this subpart, units that use a supplemental fuel only for startup, unit shutdown, and transient flame stability purposes still qualify as units that burn a single type of fuel, and the supplemental fuel is not subject to the fuel analysis requirements under § 63.7521 and Table 6 to this subpart.

(ii) When natural gas, refinery gas, or other gas 1 fuels are co-fired with other fuels, you are not required to conduct a fuel analysis of those Gas 1 fuels according to § 63.7521 and Table 6 to this subpart. If gaseous fuels other than natural gas, refinery gas, or other gas 1 fuels are co-fired with other fuels and those non-Gas 1 gaseous fuels are subject to another subpart of this part, part 60, part 61, or part 65, you are not required to conduct a fuel analysis of those non-Gas 1 fuels according to § 63.7521 and Table 6 to this subpart.

(iii) You are not required to conduct a chlorine fuel analysis for any gaseous fuels. You must conduct a fuel analysis for mercury on gaseous fuels unless the fuel is exempted in paragraphs (a)(2)(i) and (ii) of this section.

(3) Establish operating limits according to § 63.7530 and Table 7 to this subpart.

(4) Conduct CMS performance evaluations according to § 63.7525.

(b) For each boiler or process heater that you elect to demonstrate compliance with the applicable emission limits in Table 1 or 2 or Tables 11 through 15 to this subpart for HCl, mercury, or TSM through fuel analysis, your initial compliance requirement is to conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to § 63.7521 and Table 6 to this subpart and establish operating limits according to § 63.7530 and Table 8 to this subpart. The fuels described in paragraphs (a)(2)(i) and (ii) of this section are exempt from these fuel analysis and operating limit requirements. The fuels described in paragraph (a)(2)(ii) of this section are exempt from the chloride fuel analysis and operating limit requirements. Boilers and process heaters that use a CEMS for mercury or HCl are exempt from the performance testing and operating limit requirements specified in paragraph (a) of this section for the HAP for which CEMS are used.

(c) If your boiler or process heater is subject to a carbon monoxide (CO) limit, your initial compliance demonstration for CO is to conduct a performance test for CO according to Table 5 to this subpart or conduct a performance evaluation of your continuous CO monitor, if applicable, according to § 63.7525(a). Boilers and process heaters that use a CO CEMS to comply with the applicable alternative CO CEMS emission standard listed in Table 1 or 2 or Tables 11 through 15 to this subpart, as specified in § 63.7525(a), are exempt from the initial CO performance testing and oxygen concentration operating limit requirements specified in paragraph (a) of this section.

(d) If your boiler or process heater is subject to a PM limit, your initial compliance demonstration for PM is to conduct a performance test in accordance with § 63.7520 and Table 5 to this subpart.

(e) For existing affected sources (as defined in § 63.7490), you must complete the initial compliance demonstrations, as specified in paragraphs (a) through (d) of this section, no later than 180 days after the compliance date that is specified for your source in § 63.7495 and according to the applicable provisions in § 63.7(a)(2) as cited in Table 10 to this subpart, except as specified in paragraph (j) of this section. You must complete an initial tune-up by following the procedures described in § 63.7540(a)(10)(i) through (vi) no later than the compliance date specified in § 63.7495, except as specified in paragraph (j) of this section. You must complete the one-time energy assessment specified in Table 3 to this subpart no later than the compliance date specified in § 63.7495.

(f) For new or reconstructed affected sources (as defined in § 63.7490), you must complete the initial compliance demonstration with the emission limits no later than July 30, 2013, or within 180 days after startup of the source, whichever is later.

(1) If you are demonstrating compliance with an emission limit in Tables 11 through 13 to this subpart that is less stringent than the applicable emission limit in Table 14 to this subpart, you must demonstrate compliance with the applicable emission limit in Table 14 no later than July 29, 2016.

(2) If you are demonstrating compliance with an emission limit in Table 14 to this subpart that is less stringent than the applicable emission limit in Table 1 to this subpart, you must demonstrate compliance with the applicable emission limit in Table 1 no later than October 6, 2025.

(g) For new or reconstructed affected sources (as defined in § 63.7490), you must demonstrate initial compliance with the applicable work practice standards in Table 3 to this subpart within the applicable annual, biennial, or 5-year schedule as specified in § 63.7515(d) following the initial compliance date specified in § 63.7495(a). Thereafter, you are required to complete the applicable annual, biennial, or 5-year tune-up as specified in § 63.7515(d).

(h) For affected sources (as defined in § 63.7490) that ceased burning solid waste consistent with § 63.7495(e) and for which the initial compliance date has passed, you must demonstrate compliance within 60 days of the effective date of the waste-to-fuel switch. If you have not conducted your compliance demonstration for this subpart within the previous 12 months, you must complete all compliance demonstrations for this subpart before you commence or recommence combustion of solid waste.

(i) For an existing EGU that becomes subject after January 31, 2016, you must demonstrate compliance within 180 days after becoming an affected source.

(j) For existing affected sources (as defined in § 63.7490) that have not operated between the effective date of the rule and the compliance date that is specified for your source in § 63.7495, you must complete the initial compliance demonstration, if subject to the emission limits in Table 2 or 14 to this subpart, as applicable, as

specified in paragraphs (a) through (d) of this section, no later than 180 days after the re-start of the affected source and according to the applicable provisions in § 63.7(a)(2) as cited in Table 10 to this subpart. You must complete an initial tune-up by following the procedures described in § 63.7540(a)(10)(i) through (vi) no later than 30 days after the re-start of the affected source and, if applicable, complete the one-time energy assessment specified in Table 3 to this subpart, no later than the compliance date specified in § 63.7495.

(k) For affected sources, as defined in § 63.7490, that switch subcategories consistent with § 63.7545(h) after the initial compliance date, you must demonstrate compliance within 60 days of the effective date of the switch, unless you had previously conducted your compliance demonstration for this subcategory within the previous 12 months.

[78 FR 7164, Jan. 31, 2013, as amended at 80 FR 72808, Nov. 20, 2015; 87 FR 60841, Oct. 6, 2022]

### **§ 63.7515 When must I conduct subsequent performance tests, fuel analyses, or tune-ups?**

(a) You must conduct all applicable performance tests according to § 63.7520 on an annual basis, except as specified in paragraphs (b) through (e), (g), and (h) of this section. Annual performance tests must be completed no more than 13 months after the previous performance test, except as specified in paragraphs (b) through (e), (g), and (h) of this section.

(b) If your performance tests for a given pollutant for at least 2 consecutive years show that your emissions are at or below 75 percent of the emission limit (or, in limited instances as specified in Tables 1 and 2 or 11 through 15 to this subpart, at or below the emission limit) for the pollutant, and if there are no changes in the operation of the individual boiler or process heater or air pollution control equipment that could increase emissions, you may choose to conduct performance tests for the pollutant every third year. Each such performance test must be conducted no more than 37 months after the previous performance test. If you elect to demonstrate compliance using emission averaging under § 63.7522, you must continue to conduct performance tests annually. The requirement to test at maximum chloride input level is waived unless the stack test is conducted for HCl. The requirement to test at maximum mercury input level is waived unless the stack test is conducted for mercury. The requirement to test at maximum TSM input level is waived unless the stack test is conducted for TSM.

(c) If a performance test shows emissions exceeded the emission limit or 75 percent of the emission limit (as specified in Tables 1 and 2 or 11 through 15 to this subpart) for a pollutant, you must conduct annual performance tests for that pollutant until all performance tests over a consecutive 2-year period meet the required level (at or below 75 percent of the emission limit, as specified in Tables 1 and 2 or 11 through 15).

(d) If you are required to meet an applicable tune-up work practice standard, you must conduct an annual, biennial, or 5-year performance tune-up according to § 63.7540(a)(10), (11), or (12), respectively. Each annual tune-up specified in § 63.7540(a)(10) must be no more than 13 months after the previous tune-up. Each biennial tune-up specified in § 63.7540(a)(11) must be conducted no more than 25 months after the previous tune-up. Each 5-year tune-up specified in § 63.7540(a)(12) must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed affected source (as defined in § 63.7490), the first annual, biennial, or 5-year tune-up must be no later than 13 months, 25 months, or 61 months, respectively, after April 1, 2013 or the initial startup of the new or reconstructed affected source, whichever is later.

(e) If you demonstrate compliance with the mercury, HCl, or TSM based on fuel analysis, you must conduct a monthly fuel analysis according to § 63.7521 for each type of fuel burned that is subject to an emission limit in Table 1 or 2 or Tables 11 through 15 to this subpart. You may comply with this monthly requirement by completing the fuel analysis any time within the calendar month as long as the analysis is separated from the previous analysis by at least 14 calendar days. If you burn a new type of fuel, you must conduct a fuel analysis before burning the new type of fuel in your boiler or process heater. You must still meet all applicable continuous compliance requirements in § 63.7540. If each of 12 consecutive monthly fuel analyses demonstrates 75 percent or less of the compliance level, you may decrease the fuel analysis frequency to quarterly for that fuel. If any quarterly sample exceeds 75 percent of the compliance level or you begin burning a new type of fuel, you must return to monthly monitoring for that fuel, until 12 months of fuel analyses are again less than 75 percent of the compliance level. If sampling is conducted on 1 day per month, samples should be no less than 14 days apart, but if multiple samples are taken per month, the 14-day restriction does not apply.

(f) You must report the results of performance tests and the associated fuel analyses within 60 days after the completion of the performance tests. This report must also verify that the operating limits for each boiler or process

heater have not changed or provide documentation of revised operating limits established according to § 63.7530 and Table 7 to this subpart, as applicable. The reports for all subsequent performance tests must include all applicable information required in § 63.7550.

(g) For affected sources (as defined in § 63.7490) that have not operated since the previous compliance demonstration and more than 1 year has passed since the previous compliance demonstration, you must complete the subsequent compliance demonstration, if subject to the emission limits in Table 1 or 2 or Tables 11 through 15 to this subpart, no later than 180 days after the re-start of the affected source and according to the applicable provisions in § 63.7(a)(2) as cited in Table 10 to this subpart. You must complete a subsequent tune-up by following the procedures described in § 63.7540(a)(10)(i) through (vi) and the schedule described in § 63.7540(a)(13) for units that are not operating at the time of their scheduled tune-up.

(h) If your affected boiler or process heater is in the unit designed to burn light liquid subcategory and you combust ultra-low sulfur liquid fuel, you do not need to conduct further performance tests (stack tests or fuel analyses) if the pollutants measured during the initial compliance performance tests meet the emission limits in Tables 1 or 2 of this subpart providing you demonstrate ongoing compliance with the emissions limits by monitoring and recording the type of fuel combusted on a monthly basis. If you intend to use a fuel other than ultra-low sulfur liquid fuel, natural gas, refinery gas, or other gas 1 fuel, you must conduct new performance tests within 60 days of burning the new fuel type.

(i) If you operate a CO CEMS that meets the Performance Specifications outlined in § 63.7525(a)(3) to demonstrate compliance with the applicable alternative CO CEMS emission standard listed in Table 1 or 2 or Tables 11 through 15 to this subpart, you are not required to conduct CO performance tests and are not subject to the oxygen concentration operating limit requirement specified in § 63.7510(a).

[78 FR 7165, Jan. 31, 2013, as amended at 80 FR 72808, Nov. 20, 2015; 87 FR 60842, Oct. 6, 2022]

#### **§ 63.7520 What stack tests and procedures must I use?**

(a) You must conduct all performance tests according to § 63.7(c), (d), (f), and (h). You must also develop a site-specific stack test plan according to the requirements in § 63.7(c). You shall conduct all performance tests under such conditions as the Administrator specifies to you based on the representative performance of each boiler or process heater for the period being tested. Upon request, you shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests.

(b) You must conduct each performance test according to the requirements in Table 5 to this subpart.

(c) You must conduct each performance test under the specific conditions listed in Tables 5 and 7 to this subpart. You must conduct performance tests at representative operating load conditions while burning the type of fuel or mixture of fuels that has the highest content of chlorine and mercury, and TSM if you are opting to comply with the TSM alternative standard and you must demonstrate initial compliance and establish your operating limits based on these performance tests. These requirements could result in the need to conduct more than one performance test. Following each performance test and until the next performance test, you must comply with the operating limit for operating load conditions specified in Table 4 to this subpart.

(d) You must conduct a minimum of three separate test runs for each performance test required in this section, as specified in § 63.7(e)(3). Each test run must comply with the minimum applicable sampling times or volumes specified in Tables 1 and 2 or 11 through 15 to this subpart.

(e) To determine compliance with the emission limits, you must use the F-Factor methodology and equations in sections 12.2 and 12.3 of EPA Method 19 at 40 CFR part 60, appendix A-7 of this chapter to convert the measured particulate matter (PM) concentrations, the measured HCl concentrations, the measured mercury concentrations, and the measured TSM concentrations that result from the performance test to pounds per million Btu heat input emission rates.

(f) Except for a 30-day rolling average based on CEMS (or sorbent trap monitoring system) data, if measurement results for any pollutant are reported as below the method detection level (e.g., laboratory analytical results for one or more sample components are below the method defined analytical detection level), you must use the method

detection level as the measured emissions level for that pollutant in calculating compliance. The measured result for a multiple component analysis (e.g., analytical values for multiple Method 29 fractions both for individual HAP metals and for total HAP metals) may include a combination of method detection level data and analytical data reported above the method detection level.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7166, Jan. 31, 2013; 87 FR 60842, Oct. 6, 2022]

**§ 63.7521 What fuel analyses, fuel specification, and procedures must I use?**

(a) For solid and liquid fuels, you must conduct fuel analyses for chloride and mercury according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable. For solid fuels and liquid fuels, you must also conduct fuel analyses for TSM if you are opting to comply with the TSM alternative standard. For gas 2 (other) fuels, you must conduct fuel analyses for mercury according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable. For gaseous fuels, you may not use fuel analyses to comply with the TSM alternative standard or the HCl standard. For purposes of complying with this section, a fuel gas system that consists of multiple gaseous fuels collected and mixed with each other is considered a single fuel type and sampling and analysis is only required on the combined fuel gas system that will feed the boiler or process heater. Sampling and analysis of the individual gaseous streams prior to combining is not required. You are not required to conduct fuel analyses for fuels used for only startup, unit shutdown, and transient flame stability purposes. You are required to conduct fuel analyses only for fuels and units that are subject to emission limits for mercury, HCl, or TSM in Tables 1 and 2 or 11 through 15 to this subpart. Gaseous and liquid fuels are exempt from the sampling requirements in paragraphs (c) and (d) of this section.

(b) You must develop a site-specific fuel monitoring plan according to the following procedures and requirements in paragraphs (b)(1) and (2) of this section, if you are required to conduct fuel analyses as specified in § 63.7510.

(1) If you intend to use an alternative analytical method other than those required by Table 6 to this subpart, you must submit the fuel analysis plan to the Administrator for review and approval no later than 60 days before the date that you intend to conduct the initial compliance demonstration described in § 63.7510.

(2) You must include the information contained in paragraphs (b)(2)(i) through (vi) of this section in your fuel analysis plan.

(i) The identification of all fuel types anticipated to be burned in each boiler or process heater.

(ii) For each anticipated fuel type, the notification of whether you or a fuel supplier will be conducting the fuel analysis.

(iii) For each anticipated fuel type, a detailed description of the sample location and specific procedures to be used for collecting and preparing the composite samples if your procedures are different from paragraph (c) or (d) of this section. Samples should be collected at a location that most accurately represents the fuel type, where possible, at a point prior to mixing with other dissimilar fuel types.

(iv) For each anticipated fuel type, the analytical methods from Table 6, with the expected minimum detection levels, to be used for the measurement of chlorine or mercury.

(v) If you request to use an alternative analytical method other than those required by Table 6 to this subpart, you must also include a detailed description of the methods and procedures that you are proposing to use. Methods in Table 6 shall be used until the requested alternative is approved.

(vi) If you will be using fuel analysis from a fuel supplier in lieu of site-specific sampling and analysis, the fuel supplier must use the analytical methods required by Table 6 to this subpart.

(c) You must obtain composite fuel samples for each fuel type according to the procedures in paragraph (c)(1) or (2) of this section, or the methods listed in Table 6 to this subpart, or use an automated sampling mechanism that provides representative composite fuel samples for each fuel type that includes both coarse and fine material. At a minimum, for demonstrating initial compliance by fuel analysis, you must obtain three composite samples. For monthly fuel analyses, at a minimum, you must obtain a single composite sample. For fuel analyses as part of a

performance stack test, as specified in § 63.7510(a), you must obtain a composite fuel sample during each performance test run.

(1) If sampling from a belt (or screw) feeder, collect fuel samples according to paragraphs (c)(1)(i) and (ii) of this section.

(i) Stop the belt and withdraw a 6-inch wide sample from the full cross-section of the stopped belt to obtain a minimum two pounds of sample. You must collect all the material (fines and coarse) in the full cross-section. You must transfer the sample to a clean plastic bag.

(ii) Each composite sample will consist of a minimum of three samples collected at approximately equal intervals during the testing period for sampling during performance stack testing.

(2) If sampling from a fuel pile or truck, you must collect fuel samples according to paragraphs (c)(2)(i) through (iii) of this section.

(i) For each composite sample, you must select a minimum of five sampling locations uniformly spaced over the surface of the pile.

(ii) At each sampling site, you must dig into the pile to a uniform depth of approximately 18 inches. You must insert a clean shovel into the hole and withdraw a sample, making sure that large pieces do not fall off during sampling; use the same shovel to collect all samples.

(iii) You must transfer all samples to a clean plastic bag for further processing.

(d) You must prepare each composite sample according to the procedures in paragraphs (d)(1) through (7) of this section.

(1) You must thoroughly mix and pour the entire composite sample over a clean plastic sheet.

(2) You must break large sample pieces (e.g., larger than 3 inches) into smaller sizes.

(3) You must make a pie shape with the entire composite sample and subdivide it into four equal parts.

(4) You must separate one of the quarter samples as the first subset.

(5) If this subset is too large for grinding, you must repeat the procedure in paragraph (d)(3) of this section with the quarter sample and obtain a one-quarter subset from this sample.

(6) You must grind the sample in a mill.

(7) You must use the procedure in paragraph (d)(3) of this section to obtain a one-quarter subsample for analysis. If the quarter sample is too large, subdivide it further using the same procedure.

(e) You must determine the concentration of pollutants in the fuel (mercury and/or chlorine and/or TSM) in units of pounds per million Btu of each composite sample for each fuel type according to the procedures in Table 6 to this subpart, for use in Equations 7, 8, and 9 of this subpart.

(f) To demonstrate that a gaseous fuel other than natural gas or refinery gas qualifies as an other gas 1 fuel, as defined in § 63.7575, you must conduct a fuel specification analyses for mercury according to the procedures in paragraphs (g) through (i) of this section and Table 6 to this subpart, as applicable, except as specified in paragraph (f)(1) through (4) of this section, or as an alternative where fuel specification analysis is not practical, you must measure mercury concentration in the exhaust gas when firing only the gaseous fuel to be demonstrated as an other gas 1 fuel in the boiler or process heater according to the procedures in Table 6 to this subpart.

(1) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for natural gas or refinery gas.

(2) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for gaseous fuels that are subject to another subpart of this part, part 60, part 61, or part 65.

(3) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section on gaseous fuels for units that are complying with the limits for units designed to burn gas 2 (other) fuels.

(4) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for gas streams directly derived from natural gas at natural gas production sites or natural gas plants.

(g) You must develop a site-specific fuel analysis plan for other gas 1 fuels according to the following procedures and requirements in paragraphs (g)(1) and (2) of this section.

(1) If you intend to use an alternative analytical method other than those required by Table 6 to this subpart, you must submit the fuel analysis plan to the Administrator for review and approval no later than 60 days before the date that you intend to conduct the initial compliance demonstration described in § 63.7510.

(2) You must include the information contained in paragraphs (g)(2)(i) through (vi) of this section in your fuel analysis plan.

(i) The identification of all gaseous fuel types other than those exempted from fuel specification analysis under (f)(1) through (3) of this section anticipated to be burned in each boiler or process heater.

(ii) For each anticipated fuel type, the identification of whether you or a fuel supplier will be conducting the fuel specification analysis.

(iii) For each anticipated fuel type, a detailed description of the sample location and specific procedures to be used for collecting and preparing the samples if your procedures are different from the sampling methods contained in Table 6 to this subpart. Samples should be collected at a location that most accurately represents the fuel type, where possible, at a point prior to mixing with other dissimilar fuel types. If multiple boilers or process heaters are fueled by a common fuel stream it is permissible to conduct a single gas specification at the common point of gas distribution.

(iv) For each anticipated fuel type, the analytical methods from Table 6 to this subpart, with the expected minimum detection levels, to be used for the measurement of mercury.

(v) If you request to use an alternative analytical method other than those required by Table 6 to this subpart, you must also include a detailed description of the methods and procedures that you are proposing to use. Methods in Table 6 to this subpart shall be used until the requested alternative is approved.

(vi) If you will be using fuel analysis from a fuel supplier in lieu of site-specific sampling and analysis, the fuel supplier must use the analytical methods required by Table 6 to this subpart. When using a fuel supplier's fuel analysis, the owner or operator is not required to submit the information in § 63.7521(g)(2)(iii).

(h) You must obtain a single fuel sample for each fuel type for fuel specification of gaseous fuels.

(i) You must determine the concentration in the fuel of mercury, in units of microgram per cubic meter, dry basis, of each sample for each other gas 1 fuel type according to the procedures in Table 6 to this subpart.

**§ 63.7522 Can I use emissions averaging to comply with this subpart?**

(a) As an alternative to meeting the requirements of § 63.7500 for PM (or TSM), HCl, or mercury on a boiler or process heater-specific basis, if you have more than one existing boiler or process heater in any subcategories located at your facility, you may demonstrate compliance by emissions averaging, if your averaged emissions are not more than 90 percent of the applicable emission limit, according to the procedures in this section. You may not include new boilers or process heaters in an emissions average.

(b) For a group of two or more existing boilers or process heaters in the same subcategory that each vent to a separate stack, you may average PM (or TSM), HCl, or mercury emissions among existing units to demonstrate compliance with the limits in Table 2 or 15 to this subpart as specified in paragraphs (b)(1) through (3) of this section, if you satisfy the requirements in paragraphs (c) through (g) of this section.

(1) You may average units using a CEMS or PM CPMS for demonstrating compliance.

(2) For mercury and HCl, averaging is allowed as follows:

(i) You may average among units in any of the solid fuel subcategories.

(ii) You may average among units in any of the liquid fuel subcategories.

(iii) You may average among units in a subcategory of units designed to burn gas 2 (other) fuels.

(iv) You may not average across the units designed to burn liquid, units designed to burn solid fuel, and units designed to burn gas 2 (other) subcategories.

(3) For PM (or TSM), averaging is only allowed between units within each of the following subcategories and you may not average across subcategories:

(i) Units designed to burn coal/solid fossil fuel.

(ii) Stokers/sloped grate/other units designed to burn kiln dried biomass/bio-based solids.

(iii) Stokers/sloped grate/other units designed to burn wet biomass/bio-based solids.

(iv) Fluidized bed units designed to burn biomass/bio-based solid.

(v) Suspension burners designed to burn biomass/bio-based solid.

(vi) Dutch ovens/pile burners designed to burn biomass/bio-based solid.

(vii) Fuel Cells designed to burn biomass/bio-based solid.

(viii) Hybrid suspension/grate burners designed to burn wet biomass/bio-based solid.

(ix) Units designed to burn heavy liquid fuel.

(x) Units designed to burn light liquid fuel.

(xi) Units designed to burn liquid fuel that are non-continental units.

(xii) Units designed to burn gas 2 (other) gases.



(c) For each existing boiler or process heater in the averaging group, the emission rate achieved during the initial compliance test for the HAP being averaged must not exceed the emission level that was being achieved on April 1, 2013 or the control technology employed during the initial compliance test must not be less effective for the HAP being averaged than the control technology employed on April 1, 2013.

(d) The averaged emissions rate from the existing boilers and process heaters participating in the emissions averaging option must not exceed 90 percent of the limits in Table 2 or 15 to this subpart at all times the affected units are subject to numeric emission limits following the compliance date specified in § 63.7495.

(e) You must demonstrate initial compliance according to paragraph (e)(1) or (2) of this section using the maximum rated heat input capacity or maximum steam generation capacity of each unit and the results of the initial performance tests or fuel analysis.

(1) You must use Equation 1a or 1b or 1c to this paragraph (e)(1) to demonstrate that the PM (or TSM), HCl, or mercury emissions from all existing units participating in the emissions averaging option for that pollutant do not exceed the emission limits in Table 2 or 15 to this subpart. Use Equation 1a if you are complying with the emission limits on a heat input basis, use Equation 1b if you are complying with the emission limits on a steam generation (output) basis, and use Equation 1c if you are complying with the emission limits on a electric generation (output) basis.

### Equation 1a to paragraph (e)(1)

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^n (Er \times Hm) \div \sum_{i=1}^n Hm \quad (\text{Eq. 1a})$$

Where:

*AveWeightedEmissions* = Average weighted emissions for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input.

*Er* = Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or mercury from unit, *i*, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in § 63.7530(c).

*Hm* = Maximum rated heat input capacity of unit, *i*, in units of million Btu per hour.

*n* = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

### Equation 1b to paragraph (e)(1)

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^n (Er \times So) \div \sum_{i=1}^n So \quad (\text{Eq. 1b})$$

Where:

*AveWeightedEmissions* = Average weighted emissions for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of steam output.

*Er* = Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or mercury from unit, *i*, in units of pounds per million Btu of steam output. Determine the emission rate for PM (or TSM), HCl, or

mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in § 63.7530(c). If you are taking credit for energy conservation measures from a unit according to § 63.7533, use the adjusted emission level for that unit, Eadj, determined according to § 63.7533 for that unit.

So = Maximum steam output capacity of unit, i, in units of million Btu per hour, as defined in § 63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

### Equation 1c to paragraph (e)(1)

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^n (Er \times Eo) \div \sum_{i=1}^n Eo \quad (\text{Eq. 1c})$$

Where:

*AveWeightedEmissions* = Average weighted emissions for PM (or TSM), HCl, or mercury, in units of pounds per megawatt hour.

*Er* = Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per megawatt hour. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in § 63.7530(c). If you are taking credit for energy conservation measures from a unit according to § 63.7533, use the adjusted emission level for that unit, Eadj, determined according to § 63.7533 for that unit.

*Eo* = Maximum electric generating output capacity of unit, i, in units of megawatt hour, as defined in § 63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

(2) If you are not capable of determining the maximum rated heat input capacity of one or more boilers that generate steam, you may use Equation 2 to this paragraph (e)(2) as an alternative to using Equation 1a of paragraph (e)(1) of this section to demonstrate that the PM (or TSM), HCl, or mercury emissions from all existing units participating in the emissions averaging option do not exceed the emission limits for that pollutant in Table 2 or 15 to this subpart that are in pounds per million Btu of heat input.

### Equation 2 to paragraph (e)(2)

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^n (Er \times Sm \times Cfi) \div \sum_{i=1}^n (Sm \times Cfi) \quad (\text{Eq. 2})$$

Where:

*AveWeightedEmissions* = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input.

*Er* = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in § 63.7530(c).

$S_m$  = Maximum steam generation capacity by unit,  $i$ , in units of pounds per hour.

$C_{fi}$  = Conversion factor, calculated from the most recent compliance test, in units of million Btu of heat input per pounds of steam generated for unit,  $i$ .

1.1 = Required discount factor.

(f) After the initial compliance demonstration described in paragraph (e) of this section, you must demonstrate compliance on a monthly basis determined at the end of every month (12 times per year) according to paragraphs (f)(1) through (3) of this section. The first monthly period begins on the compliance date specified in § 63.7495. If the affected source elects to collect monthly data for up to the 11 months preceding the first monthly period, these additional data points can be used to compute the 12-month rolling average in paragraph (f)(3) of this section.

(1) For each calendar month, you must use Equation 3a or 3b or 3c of this section to calculate the average weighted emission rate for that month. Use Equation 3a and the actual heat input for the month for each existing unit participating in the emissions averaging option if you are complying with emission limits on a heat input basis. Use Equation 3b and the actual steam generation for the month if you are complying with the emission limits on a steam generation (output) basis. Use Equation 3c and the actual electrical generation for the month if you are complying with the emission limits on an electrical generation (output) basis.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^n (Er \times Hb) \div \sum_{i=1}^n Hb \quad (\text{Eq. 3a})$$

Where:

$AveWeightedEmissions$  = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input, for that calendar month.

$Er$  = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit,  $i$ , in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart.

$Hb$  = The heat input for that calendar month to unit,  $i$ , in units of million Btu.

$n$  = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^n (Er \times So) \div \sum_{i=1}^n So \quad (\text{Eq. 3b})$$

Where:

$AveWeightedEmissions$  = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of steam output, for that calendar month.

$Er$  = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit,  $i$ , in units of pounds per million Btu of steam output. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart. If you are taking credit for energy conservation measures from a unit according to § 63.7533, use the adjusted emission level for that unit,  $E_{adj}$ , determined according to § 63.7533 for that unit.

So = The steam output for that calendar month from unit, i, in units of million Btu, as defined in § 63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

$$\text{AveWeightedEmissions} = 1.1 \times \sum_{i=1}^n (Er \times Eo) \div \sum_{i=1}^n Eo \quad (\text{Eq. 3c})$$

Where:

AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per megawatt hour, for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per megawatt hour. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart. If you are taking credit for energy conservation measures from a unit according to § 63.7533, use the adjusted emission level for that unit,  $E_{adj}$ , determined according to § 63.7533 for that unit.

Eo = The electric generating output for that calendar month from unit, i, in units of megawatt hour, as defined in § 63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

(2) If you are not capable of monitoring heat input, you may use Equation 4 of this section as an alternative to using Equation 3a of this section to calculate the average weighted emission rate using the actual steam generation from the boilers participating in the emissions averaging option.

$$\text{AveWeightedEmissions} = 1.1 \times \sum_{i=1}^n (Er \times Sa \times Cfi) \div \sum_{i=1}^n (Sa \times Cfi) \quad (\text{Eq. 4})$$

Where:

AveWeightedEmissions = average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart.

Sa = Actual steam generation for that calendar month by boiler, i, in units of pounds.

Cfi = Conversion factor, as calculated during the most recent compliance test, in units of million Btu of heat input per pounds of steam generated for boiler, i.

1.1 = Required discount factor.

(3) Until 12 monthly weighted average emission rates have been accumulated, calculate and report only the average weighted emission rate determined under paragraph (f)(1) or (2) of this section for each calendar month.

After 12 monthly weighted average emission rates have been accumulated, for each subsequent calendar month, use Equation 5 of this section to calculate the 12-month rolling average of the monthly weighted average emission rates for the current calendar month and the previous 11 calendar months.

$$E_{avg} = \sum_{i=1}^n ER_i \div 12 \quad (\text{Eq. 5})$$

Where:

$E_{avg}$  = 12-month rolling average emission rate, (pounds per million Btu heat input)

$ER_i$  = Monthly weighted average, for calendar month "i" (pounds per million Btu heat input), as calculated by paragraph (f)(1) or (2) of this section.

(g) You must develop, and submit upon request to the applicable Administrator for review and approval, an implementation plan for emission averaging according to the following procedures and requirements in paragraphs (g)(1) through (4) of this section.

(1) If requested, you must submit the implementation plan no later than 180 days before the date that the facility intends to demonstrate compliance using the emission averaging option.

(2) You must include the information contained in paragraphs (g)(2)(i) through (vii) of this section in your implementation plan for all emission sources included in an emissions average:

(i) The identification of all existing boilers and process heaters in the averaging group, including for each either the applicable HAP emission level or the control technology installed as of January 31, 2013 and the date on which you are requesting emission averaging to commence;

(ii) The process parameter (heat input or steam generated) that will be monitored for each averaging group;

(iii) The specific control technology or pollution prevention measure to be used for each emission boiler or process heater in the averaging group and the date of its installation or application. If the pollution prevention measure reduces or eliminates emissions from multiple boilers or process heaters, the owner or operator must identify each boiler or process heater;

(iv) The test plan for the measurement of PM (or TSM), HCl, or mercury emissions in accordance with the requirements in § 63.7520;

(v) The operating parameters to be monitored for each control system or device consistent with § 63.7500 and Table 4, and a description of how the operating limits will be determined;

(vi) If you request to monitor an alternative operating parameter pursuant to § 63.7525, you must also include:

(A) A description of the parameter(s) to be monitored and an explanation of the criteria used to select the parameter(s); and

(B) A description of the methods and procedures that will be used to demonstrate that the parameter indicates proper operation of the control device; the frequency and content of monitoring, reporting, and recordkeeping requirements; and a demonstration, to the satisfaction of the Administrator, that the proposed monitoring frequency is sufficient to represent control device operating conditions; and

(vii) A demonstration that compliance with each of the applicable emission limit(s) will be achieved under representative operating load conditions. Following each compliance demonstration and until the next

compliance demonstration, you must comply with the operating limit for operating load conditions specified in Table 4 to this subpart.

(3) If submitted upon request, the Administrator shall review and approve or disapprove the plan according to the following criteria:

(i) Whether the content of the plan includes all of the information specified in paragraph (g)(2) of this section; and

(ii) Whether the plan presents sufficient information to determine that compliance will be achieved and maintained.

(4) The applicable Administrator shall not approve an emission averaging implementation plan containing any of the following provisions:

(i) Any averaging between emissions of differing pollutants or between differing sources; or

(ii) The inclusion of any emission source other than an existing unit in the same subcategories.

(h) For a group of two or more existing affected units, each of which vents through a single common stack, you may average PM (or TSM), HCl, or mercury emissions to demonstrate compliance with the limits for that pollutant in Table 2 or 15 to this subpart if you satisfy the requirements in paragraph (i) or (j) of this section.

(i) For a group of two or more existing units in the same subcategory, each of which vents through a common emissions control system to a common stack, that does not receive emissions from units in other subcategories or categories, you may treat such averaging group as a single existing unit for purposes of this subpart and comply with the requirements of this subpart as if the group were a single unit.

(j) For all other groups of units subject to the common stack requirements of paragraph (h) of this section, including situations where the exhaust of affected units are each individually controlled and then sent to a common stack, the owner or operator may elect to:

(1) Conduct performance tests according to procedures specified in § 63.7520 in the common stack if affected units from other subcategories vent to the common stack. The emission limits that the group must comply with are determined by the use of Equation 6 to this paragraph (j)(1).

## Equation 6 to paragraph (j)(1)

$$En = \sum_{i=1}^n (ELi \times Hi) + \sum_{i=1}^n Hi \quad (\text{Eq. 6})$$

Where:

$En$  = HAP emission limit, pounds per million British thermal units (lb/MMBtu) or parts per million (ppm).

$ELi$  = Appropriate emission limit from Table 2 or 15 to this subpart for unit  $i$ , in units of lb/MMBtu or ppm.

$Hi$  = Heat input from unit  $i$ , MMBtu.

(2) Conduct performance tests according to procedures specified in § 63.7520 in the common stack. If affected units and non-affected units vent to the common stack, the non-affected units must be shut down or vented to a different stack during the performance test unless the facility determines to demonstrate compliance with the non-affected units venting to the stack; and

(3) Meet the applicable operating limit specified in § 63.7540 and Table 8 to this subpart for each emissions control system (except that, if each unit venting to the common stack has an applicable opacity operating limit, then a single continuous opacity monitoring system may be located in the common stack instead of in each duct to the common stack).

(k) The common stack of a group of two or more existing boilers or process heaters in the same subcategories subject to paragraph (h) of this section may be treated as a separate stack for purposes of paragraph (b) of this section and included in an emissions averaging group subject to paragraph (b) of this section.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7168, Jan. 31, 2013; 80 FR 72809, Nov. 20, 2015; 87 FR 60843, Oct. 6, 2022]

**§ 63.7525 What are my monitoring, installation, operation, and maintenance requirements?**

(a) If your boiler or process heater is subject to a CO emission limit in Table 1 or 2 or Tables 11 through 15 to this subpart, you must install, operate, and maintain an oxygen analyzer system, as defined in § 63.7575, or install, certify, operate and maintain continuous emission monitoring systems for CO and oxygen (O<sub>2</sub>) (or carbon dioxide (CO<sub>2</sub>)) according to the procedures in paragraphs (a)(1) through (6) of this section.

(1) Install the CO CEMS including an O<sub>2</sub> (or CO<sub>2</sub>) analyzer by the compliance date specified in § 63.7495. The CO and O<sub>2</sub> (or CO<sub>2</sub>) levels shall be monitored at the same location at the outlet of the boiler or process heater. An owner or operator may determine compliance with the CO emissions limit using a CO<sub>2</sub> analyzer as the diluent monitor. If a CO<sub>2</sub> analyzer is used as the diluent monitor, EPA Method 19 F-factors in 40 CFR part 60, appendix A-7, for the fuel type(s) being burned in the unit and EPA Method 19 equations in 40 CFR part 60, appendix A-7, must be used to calculate the emissions corrected to 3 percent O<sub>2</sub> using the measured CO<sub>2</sub> percentage, and must also take into account that the 3 percent oxygen correction is to be done on a dry basis. The equations used to calculate the emissions, must also account for any CO<sub>2</sub> being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc. The methodology used to calculate the CO emissions and the methodology used to account for any CO<sub>2</sub> being added to, or removed from the emissions gas stream shall be detailed and approved in the site-specific monitoring plan developed according to § 63.7505(d).

(2) To demonstrate compliance with the applicable alternative CO CEMS emission standard listed in Table 1 or 2 or Tables 11 through 15 to this subpart, you must install, certify, operate, and maintain a CO CEMS and an oxygen analyzer according to the applicable procedures under Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B; part 75 of this chapter (if an CO<sub>2</sub> analyzer is used); the site-specific monitoring plan developed according to § 63.7505(d); and the requirements in § 63.7540(a)(8) and this paragraph (a). Any boiler or process heater that has a CO CEMS that is compliant with Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B, a site-specific monitoring plan developed according to § 63.7505(d), and the requirements in § 63.7540(a)(8) and this paragraph (a) must use the CO CEMS to comply with the applicable alternative CO CEMS emission standard listed in Table 1 or 2 or Tables 11 through 15 to this subpart.

(i) You must conduct a performance evaluation of each CO CEMS according to the requirements in § 63.8(e) and according to Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B.

(ii) During each relative accuracy test run of the CO CEMS, you must collect emission data for CO concurrently using both the CO CEMS and Method 10, 10A, or 10B at 40 CFR part 60, appendix A-4. The relative accuracy testing must be conducted at representative operating conditions.

(iii) You must follow the quality assurance procedures (e.g., quarterly accuracy determinations and daily calibration drift tests) of Procedure 1 of appendix F to part 60. The measurement span value of the CO CEMS must be two times the applicable CO emission limit, expressed as a concentration.

(iv) Any CO CEMS that does not comply with this paragraph (a) cannot be used to meet any requirement in this subpart to demonstrate compliance with a CO emission limit listed in Table 1 or 2 or Tables 11 through 15 to this subpart.

(v) For a new unit, complete the initial performance evaluation no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than July 29, 2016.

(vi) When CO<sub>2</sub> is used to correct CO emissions and CO<sub>2</sub> is measured on a wet basis, if needed, correct for moisture as follows: Install, operate, maintain, and quality assure a continuous moisture monitoring system for measuring and recording the moisture content of the flue gases, in order to correct the measured hourly volumetric flow rates for moisture when calculating CO concentrations. The following continuous moisture monitoring systems are acceptable: a continuous moisture sensor; an oxygen analyzer (or analyzers) capable of measuring O<sub>2</sub> both on a wet basis and on a dry basis; or a stack temperature sensor and a moisture look-up table, *i.e.*, a psychrometric chart (for saturated gas streams following wet scrubbers or other demonstrably saturated gas streams, only). The moisture monitoring system shall include as a component the automated data acquisition and handling system (DAHS) for recording and reporting both the raw data (e.g., hourly average wet-and dry-basis O<sub>2</sub> values) and the hourly average values of the stack gas moisture content derived from those data. When a moisture look-up table is used, the moisture monitoring system shall be represented as a single component, the certified DAHS, in the monitoring plan for the unit or common stack.

(3) Complete a minimum of one cycle of CO and oxygen (or CO<sub>2</sub>) CEMS operation (sampling, analyzing, and data recording) for each successive 15-minute period. Collect CO and oxygen (or CO<sub>2</sub>) data concurrently. Collect at least four CO and oxygen (or CO<sub>2</sub>) CEMS data values representing the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CEMS calibration, quality assurance, or maintenance activities are being performed.

(4) Reduce the CO CEMS data as specified in § 63.8(g)(2).

(5) Calculate one-hour arithmetic averages, corrected to 3 percent oxygen (or corrected to an CO<sub>2</sub> percentage determined to be equivalent to 3 percent oxygen) from each hour of CO CEMS data in parts per million CO concentration. The one-hour arithmetic averages required shall be used to calculate the 30-day or 10-day rolling average emissions. Use Equation 19-19 in section 12.4.1 of Method 19 of 40 CFR part 60, appendix A-7 for calculating the average CO concentration from the hourly values.

(6) For purposes of collecting CO data, operate the CO CEMS as specified in § 63.7535(b). You must use all the data collected during all periods in calculating data averages and assessing compliance, except that you must exclude certain data as specified in § 63.7535(c). Periods when CO data are unavailable may constitute monitoring deviations as specified in § 63.7535(d).

(7) Operate an oxygen trim system with the oxygen level set no lower than the lowest hourly average oxygen concentration measured during the most recent CO performance test as the operating limit for oxygen according to Table 7 to this subpart.

(b) If your boiler or process heater is in the unit designed to burn coal/solid fossil fuel subcategory or the unit designed to burn heavy liquid subcategory and has an average annual heat input rate greater than 250 MMBtu per hour from solid fossil fuel and/or heavy liquid, and you demonstrate compliance with the PM limit instead of the alternative TSM limit, you must install, maintain, and operate a PM CPMS monitoring emissions discharged to the atmosphere and record the output of the system as specified in paragraphs (b)(1) through (4) of this section. As an alternative to use of a PM CPMS to demonstrate compliance with the PM limit, you may choose to use a PM CEMS. If you choose to use a PM CEMS to demonstrate compliance with the PM limit instead of the alternative TSM limit, you must install, certify, maintain, and operate a PM CEMS monitoring emissions discharged to the atmosphere and record the output of the system as specified in paragraph (b)(5) through (8) of this section. For other boilers or process heaters, you may elect to use a PM CPMS or PM CEMS operated in accordance with this section in lieu of using other CMS for monitoring PM compliance (e.g., bag leak detectors, ESP secondary power, and PM scrubber pressure). Owners of boilers and process heaters who elect to comply with the alternative TSM limit are not required to install a PM CPMS.

(1) Install, operate, and maintain your PM CPMS according to the procedures in your approved site-specific monitoring plan developed in accordance with § 63.7505(d), the requirements in § 63.7540(a)(9), and paragraphs (b)(1)(i) through (iii) of this section.



- (i) The operating principle of the PM CPMS must be based on in-stack or extractive light scatter, light scintillation, beta attenuation, or mass accumulation detection of PM in the exhaust gas or representative exhaust gas sample. The reportable measurement output from the PM CPMS must be expressed as milliamps.
  - (ii) The PM CPMS must have a cycle time (i.e., period required to complete sampling, measurement, and reporting for each measurement) no longer than 60 minutes.
  - (iii) The PM CPMS must have a documented detection limit of 0.5 milligram per actual cubic meter, or less.
- (2) For a new unit, complete the initial performance evaluation no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than July 29, 2016.
- (3) Collect PM CPMS hourly average output data for all boiler or process heater operating hours except as indicated in § 63.7535(a) through (d). Express the PM CPMS output as milliamps.
- (4) Calculate the arithmetic 30-day rolling average of all of the hourly average PM CPMS output data collected during all boiler or process heater operating hours (milliamps).
- (5) Install, certify, operate, and maintain your PM CEMS according to the procedures in your approved site-specific monitoring plan developed in accordance with § 63.7505(d), the requirements in § 63.7540(a)(9), and paragraphs (b)(5)(i) through (iv) of this section.
- (i) You shall conduct a performance evaluation of the PM CEMS according to the applicable requirements of § 60.8(e), and Performance Specification 11 at 40 CFR part 60, appendix B of this chapter.
  - (ii) During each PM correlation testing run of the CEMS required by Performance Specification 11 at 40 CFR part 60, appendix B of this chapter, you shall collect PM and oxygen (or carbon dioxide) data concurrently (or within a 30-to 60-minute period) by both the CEMS and conducting performance tests using Method 5 at 40 CFR part 60, appendix A-3 or Method 17 at 40 CFR part 60, appendix A-6 of this chapter.
  - (iii) You shall perform quarterly accuracy determinations and daily calibration drift tests in accordance with Procedure 2 at 40 CFR part 60, appendix F of this chapter. You must perform Relative Response Audits annually and perform Response Correlation Audits every 3 years.
  - (iv) Within 60 days after the date of completing each CEMS relative accuracy test audit or performance test conducted to demonstrate compliance with this subpart, you must submit the relative accuracy test audit data and performance test data to the EPA by successfully submitting the data electronically into the EPA's Central Data Exchange by using the Electronic Reporting Tool (see <http://www.epa.gov/ttn/chief/ert/erttool.html/>).
- (6) For a new unit, complete the initial performance evaluation no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than July 29, 2016.
- (7) Collect PM CEMS hourly average output data for all boiler or process heater operating hours except as indicated in § 63.7535(a) through (d).
- (8) Calculate the arithmetic 30-day rolling average of all of the hourly average PM CEMS output data collected during all boiler or process heater operating hours.
- (c) If you have an applicable opacity operating limit in this rule, and are not otherwise required or elect to install and operate a PM CPMS, PM CEMS, or a bag leak detection system, you must install, operate, certify and maintain each COMS according to the procedures in paragraphs (c)(1) through (7) of this section by the compliance date specified in § 63.7495.

- (1) Each COMS must be installed, operated, and maintained according to Performance Specification 1 at appendix B to part 60 of this chapter.
  - (2) You must conduct a performance evaluation of each COMS according to the requirements in § 63.8(e) and according to Performance Specification 1 at appendix B to part 60 of this chapter.
  - (3) As specified in § 63.8(c)(4)(i), each COMS must complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.
  - (4) The COMS data must be reduced as specified in § 63.8(g)(2).
  - (5) You must include in your site-specific monitoring plan procedures and acceptance criteria for operating and maintaining each COMS according to the requirements in § 63.8(d). At a minimum, the monitoring plan must include a daily calibration drift assessment, a quarterly performance audit, and an annual zero alignment audit of each COMS.
  - (6) You must operate and maintain each COMS according to the requirements in the monitoring plan and the requirements of § 63.8(e). You must identify periods the COMS is out of control including any periods that the COMS fails to pass a daily calibration drift assessment, a quarterly performance audit, or an annual zero alignment audit. Any 6-minute period for which the monitoring system is out of control and data are not available for a required calculation constitutes a deviation from the monitoring requirements.
  - (7) You must determine and record all the 6-minute averages (and daily block averages as applicable) collected for periods during which the COMS is not out of control.
- (d) If you have an operating limit that requires the use of a CMS other than a PM CPMS or COMS, you must install, operate, and maintain each CMS according to the procedures in paragraphs (d)(1) through (5) of this section by the compliance date specified in § 63.7495.
- (1) The CPMS must complete a minimum of one cycle of operation every 15-minutes. You must have a minimum of four successive cycles of operation, one representing each of the four 15-minute periods in an hour, to have a valid hour of data.
  - (2) You must operate the monitoring system as specified in § 63.7535(b), and comply with the data calculation requirements specified in § 63.7535(c).
  - (3) Any 15-minute period for which the monitoring system is out-of-control and data are not available for a required calculation constitutes a deviation from the monitoring requirements. Other situations that constitute a monitoring deviation are specified in § 63.7535(d).
  - (4) You must determine the 30-day rolling average of all recorded readings, except as provided in § 63.7535(c).
  - (5) You must record the results of each inspection, calibration, and validation check.
- (e) If you have an operating limit that requires the use of a flow monitoring system, you must meet the requirements in paragraphs (d) and (e)(1) through (4) of this section.
- (1) You must install the flow sensor and other necessary equipment in a position that provides a representative flow.
  - (2) You must use a flow sensor with a measurement sensitivity of no greater than 2 percent of the design flow rate.
  - (3) You must minimize, consistent with good engineering practices, the effects of swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.

(4) You must conduct a flow monitoring system performance evaluation in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(f) If you have an operating limit that requires the use of a pressure monitoring system, you must meet the requirements in paragraphs (d) and (f)(1) through (6) of this section.

(1) Install the pressure sensor(s) in a position that provides a representative measurement of the pressure (e.g., PM scrubber pressure drop).

(2) Minimize or eliminate pulsating pressure, vibration, and internal and external corrosion consistent with good engineering practices.

(3) Use a pressure sensor with a minimum tolerance of 1.27 centimeters of water or a minimum tolerance of 1 percent of the pressure monitoring system operating range, whichever is less.

(4) Perform checks at least once each process operating day to ensure pressure measurements are not obstructed (e.g., check for pressure tap pluggage daily).

(5) Conduct a performance evaluation of the pressure monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(6) If at any time the measured pressure exceeds the manufacturer's specified maximum operating pressure range, conduct a performance evaluation of the pressure monitoring system in accordance with your monitoring plan and confirm that the pressure monitoring system continues to meet the performance requirements in your monitoring plan. Alternatively, install and verify the operation of a new pressure sensor.

(g) If you have an operating limit that requires a pH monitoring system, you must meet the requirements in paragraphs (d) and (g)(1) through (4) of this section.

(1) Install the pH sensor in a position that provides a representative measurement of scrubber effluent pH.

(2) Ensure the sample is properly mixed and representative of the fluid to be measured.

(3) Calibrate the pH monitoring system in accordance with your monitoring plan and according to the manufacturer's instructions. Clean the pH probe at least once each process operating day. Maintain on-site documentation that your calibration frequency is sufficient to maintain the specified accuracy of your device.

(4) Conduct a performance evaluation (including a two-point calibration with one of the two buffer solutions having a pH within 1 of the pH of the operating limit) of the pH monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(h) If you have an operating limit that requires a secondary electric power monitoring system for an electrostatic precipitator (ESP) operated with a wet scrubber, you must meet the requirements in paragraphs (h)(1) and (2) of this section.

(1) Install sensors to measure (secondary) voltage and current to the precipitator collection plates.

(2) Conduct a performance evaluation of the electric power monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(i) If you have an operating limit that requires the use of a monitoring system to measure sorbent injection rate (e.g., weigh belt, weigh hopper, or hopper flow measurement device), you must meet the requirements in paragraphs (d) and (i)(1) through (2) of this section.

(1) Install the system in a position(s) that provides a representative measurement of the total sorbent injection rate.

(2) Conduct a performance evaluation of the sorbent injection rate monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(j) If you are not required to use a PM CPMS and elect to use a fabric filter bag leak detection system to comply with the requirements of this subpart, you must install, calibrate, maintain, and continuously operate the bag leak detection system as specified in paragraphs (j)(1) through (6) of this section.

(1) You must install a bag leak detection sensor(s) in a position(s) that will be representative of the relative or absolute PM loadings for each exhaust stack, roof vent, or compartment (e.g., for a positive pressure fabric filter) of the fabric filter.

(2) Conduct a performance evaluation of the bag leak detection system in accordance with your monitoring plan and consistent with the guidance provided in EPA-454/R-98-015 (incorporated by reference, see § 63.14).

(3) Use a bag leak detection system certified by the manufacturer to be capable of detecting PM emissions at concentrations of 10 milligrams per actual cubic meter or less.

(4) Use a bag leak detection system equipped with a device to record continuously the output signal from the sensor.

(5) Use a bag leak detection system equipped with a system that will alert plant operating personnel when an increase in relative PM emissions over a preset level is detected. The alert must easily recognizable (e.g., heard or seen) by plant operating personnel.

(6) Where multiple bag leak detectors are required, the system's instrumentation and alert may be shared among detectors.

(k) For each unit that meets the definition of limited-use boiler or process heater, you must keep fuel use records for the days the boiler or process heater was operating.

(l) For each unit for which you decide to demonstrate compliance with the mercury or HCl emissions limits in Table 1 or 2 or Tables 11 through 15 to this subpart by use of a CEMS for mercury or HCl, you must install, certify, maintain, and operate a CEMS measuring emissions discharged to the atmosphere and record the output of the system as specified in paragraphs (l)(1) through (8) of this section. For HCl, this option for an affected unit takes effect on the date of approval of a site-specific monitoring plan.

(1) Notify the Administrator one month before starting use of the CEMS, and notify the Administrator one month before stopping use of the CEMS.

(2) Each CEMS shall be installed, certified, operated, and maintained according to the requirements in § 63.7540(a)(14) for a mercury CEMS and § 63.7540(a)(15) for a HCl CEMS.

(3) For a new unit, you must complete the initial performance evaluation of the CEMS by the latest of the dates specified in paragraph (l)(3)(i) through (iii) of this section.

(i) No later than July 30, 2013.

(ii) No later 180 days after the date of initial startup.

(iii) No later 180 days after notifying the Administrator before starting to use the CEMS in place of performance testing or fuel analysis to demonstrate compliance.

(4) For an existing unit, you must complete the initial performance evaluation by the latter of the two dates specified in paragraph (l)(4)(i) and (ii) of this section.

(i) No later than July 29, 2016.

(ii) No later 180 days after notifying the Administrator before starting to use the CEMS in place of performance testing or fuel analysis to demonstrate compliance.

(5) Compliance with the applicable emissions limit shall be determined based on the 30-day rolling average of the hourly arithmetic average emissions rates using the continuous monitoring system outlet data. The 30-day rolling arithmetic average emission rate (lb/MMBtu) shall be calculated using the equations in EPA Reference Method 19 at 40 CFR part 60, appendix A-7, but substituting the mercury or HCl concentration for the pollutant concentrations normally used in Method 19.

(6) Collect CEMS hourly averages for all operating hours on a 30-day rolling average basis. Collect at least four CMS data values representing the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CMS calibration, quality assurance, or maintenance activities are being performed.

(7) The one-hour arithmetic averages required shall be expressed in lb/MMBtu and shall be used to calculate the boiler 30-day and 10-day rolling average emissions.

(8) You are allowed to substitute the use of the PM, mercury or HCl CEMS for the applicable fuel analysis, annual performance test, and operating limits specified in Table 4 to this subpart to demonstrate compliance with the PM, mercury or HCl emissions limit, and if you are using an acid gas wet scrubber or dry sorbent injection control technology to comply with the HCl emission limit, you are allowed to substitute the use of a sulfur dioxide (SO<sub>2</sub>) CEMS for the applicable fuel analysis, annual performance test, and operating limits specified in Table 4 to this subpart to demonstrate compliance with HCl emissions limit.

(m) If your unit is subject to a HCl emission limit in Table 1 or 2 or Tables 11 through 15 to this subpart and you have an acid gas wet scrubber or dry sorbent injection control technology and you elect to use an SO<sub>2</sub> CEMS to demonstrate continuous compliance with the HCl emission limit, you must install the monitor at the outlet of the boiler or process heater, downstream of all emission control devices, and you must install, certify, operate, and maintain the CEMS according to either part 60 or part 75 of this chapter.

(1) The SO<sub>2</sub> CEMS must be installed by the compliance date specified in § 63.7495.

(2) For on-going quality assurance (QA), the SO<sub>2</sub> CEMS must meet either the applicable daily and quarterly requirements in Procedure 1 of appendix F of part 60 or the applicable daily, quarterly, and semiannual or annual requirements in sections 2.1 through 2.3 of appendix B to part 75 of this chapter, with the following addition: You must perform the linearity checks required in section 2.2 of appendix B to part 75 of this chapter if the SO<sub>2</sub> CEMS has a span value of 30 ppm or less.

(3) For a new unit, the initial performance evaluation shall be completed no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, the initial performance evaluation shall be completed no later than July 29, 2016.

(4) For purposes of collecting SO<sub>2</sub> data, you must operate the SO<sub>2</sub> CEMS as specified in § 63.7535(b). You must use all the data collected during all periods in calculating data averages and assessing compliance, except that you must exclude certain data as specified in § 63.7535(c). Periods when SO<sub>2</sub> data are unavailable may constitute monitoring deviations as specified in § 63.7535(d).

(5) Collect CEMS hourly averages for all operating hours on a 30-day rolling average basis.

(6) Use only unadjusted, quality-assured SO<sub>2</sub> concentration values in the emissions calculations; do not apply bias adjustment factors to the part 75 SO<sub>2</sub> data and do not use part 75 substitute data values.

**§ 63.7530 How do I demonstrate initial compliance with the emission limitations, fuel specifications and work practice standards?**

(a) You must demonstrate initial compliance with each emission limit that applies to you by conducting initial performance tests and fuel analyses and establishing operating limits, as applicable, according to § 63.7520, paragraphs (b) and (c) of this section, and Tables 5 and 7 to this subpart. The requirement to conduct a fuel analysis is not applicable for units that burn a single type of fuel, as specified by § 63.7510(a)(2). If applicable, you must also install, operate, and maintain all applicable CMS (including CEMS, COMS, and CPMS) according to § 63.7525.

(b) If you demonstrate compliance through performance stack testing, you must establish each site-specific operating limit in Table 4 to this subpart that applies to you according to the requirements in § 63.7520, Table 7 to this subpart, and paragraph (b)(4) of this section, as applicable. You must also conduct fuel analyses according to § 63.7521 and establish maximum fuel pollutant input levels according to paragraphs (b)(1) through (3) of this section, as applicable, and as specified in § 63.7510(a)(2). (Note that § 63.7510(a)(2) exempts certain fuels from the fuel analysis requirements.) However, if you switch fuel(s) and cannot show that the new fuel(s) does (do) not increase the chlorine, mercury, or TSM input into the unit through the results of fuel analysis, then you must repeat the performance test to demonstrate compliance while burning the new fuel(s).

(1) You must establish the maximum chlorine fuel input (Clinput) during the initial fuel analysis according to the procedures in paragraphs (b)(1)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of chlorine.

(ii) During the fuel analysis for hydrogen chloride, you must determine the fraction of the total heat input for each fuel type burned (Qi) based on the fuel mixture that has the highest content of chlorine, and the average chlorine concentration of each fuel type burned (Ci).

(iii) You must establish a maximum chlorine input level using Equation 7 of this section.

$$Clinput = \sum_{i=1}^n (Ci \times Qi) \quad (\text{Eq. 7})$$

Where:

Clinput = Maximum amount of chlorine entering the boiler or process heater through fuels burned in units of pounds per million Btu.

Ci = Arithmetic average concentration of chlorine in fuel type, i, analyzed according to § 63.7521, in units of pounds per million Btu.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of chlorine during the initial compliance test. If you do not burn multiple fuel types during the performance testing, it is not necessary to determine the value of this term. Insert a value of "1" for Qi. For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of chlorine.

(2) You must establish the maximum mercury fuel input level (Mercuryinput) during the initial fuel analysis using the procedures in paragraphs (b)(2)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of mercury.

(ii) During the compliance demonstration for mercury, you must determine the fraction of total heat input for each fuel burned ( $Q_i$ ) based on the fuel mixture that has the highest content of mercury, and the average mercury concentration of each fuel type burned ( $HG_i$ ).

(iii) You must establish a maximum mercury input level using Equation 8 of this section.

$$\text{Mercuryinput} = \sum_{i=1}^n (HG_i \times Q_i) \quad (\text{Eq. 8})$$

Where:

Mercuryinput = Maximum amount of mercury entering the boiler or process heater through fuels burned in units of pounds per million Btu.

$HG_i$  = Arithmetic average concentration of mercury in fuel type,  $i$ , analyzed according to § 63.7521, in units of pounds per million Btu.

$Q_i$  = Fraction of total heat input from fuel type,  $i$ , based on the fuel mixture that has the highest mercury content during the initial compliance test. If you do not burn multiple fuel types during the performance test, it is not necessary to determine the value of this term. Insert a value of "1" for  $Q_i$ . For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

$n$  = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of mercury.

(3) If you opt to comply with the alternative TSM limit, you must establish the maximum TSM fuel input (TSMinput) for solid or liquid fuels during the initial fuel analysis according to the procedures in paragraphs (b)(3)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of TSM.

(ii) During the fuel analysis for TSM, you must determine the fraction of the total heat input for each fuel type burned ( $Q_i$ ) based on the fuel mixture that has the highest content of TSM, and the average TSM concentration of each fuel type burned ( $TSM_i$ ).

(iii) You must establish a maximum TSM input level using Equation 9 of this section.

$$\text{TSMinput} = \sum_{i=1}^n (TSM_i \times Q_i) \quad (\text{Eq. 9})$$

Where:

TSMinput = Maximum amount of TSM entering the boiler or process heater through fuels burned in units of pounds per million Btu.

$TSM_i$  = Arithmetic average concentration of TSM in fuel type,  $i$ , analyzed according to § 63.7521, in units of pounds per million Btu.

$Q_i$  = Fraction of total heat input from fuel type,  $i$ , based on the fuel mixture that has the highest content of TSM during the initial compliance test. If you do not burn multiple fuel types during the performance testing, it is not necessary to

determine the value of this term. Insert a value of "1" for  $Q_i$ . For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of TSM.

(4) You must establish parameter operating limits according to paragraphs (b)(4)(i) through (ix) of this section. As indicated in Table 4 to this subpart, you are not required to establish and comply with the operating parameter limits when you are using a CEMS to monitor and demonstrate compliance with the applicable emission limit for that control device parameter.

(i) For a wet acid gas scrubber, you must establish the minimum scrubber effluent pH and liquid flow rate as defined in § 63.7575, as your operating limits during the performance test during which you demonstrate compliance with your applicable limit. If you use a wet scrubber and you conduct separate performance tests for HCl and mercury emissions, you must establish one set of minimum scrubber effluent pH, liquid flow rate, and pressure drop operating limits. The minimum scrubber effluent pH operating limit must be established during the HCl performance test. If you conduct multiple performance tests, you must set the minimum liquid flow rate operating limit at the higher of the minimum values established during the performance tests.

(ii) For any particulate control device (e.g., ESP, particulate wet scrubber, fabric filter) for which you use a PM CPMS, you must establish your PM CPMS operating limit and determine compliance with it according to paragraphs (b)(4)(ii)(A) through (F) of this section.

(A) Determine your operating limit as the average PM CPMS output value recorded during the most recent performance test run demonstrating compliance with the filterable PM emission limit or at the PM CPMS output value corresponding to 75 percent of the emission limit if your PM performance test demonstrates compliance below 75 percent of the emission limit. You must verify an existing or establish a new operating limit after each repeated performance test. You must repeat the performance test annually and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(1) Your PM CPMS must provide a 4-20 milliamp output and the establishment of its relationship to manual reference method measurements must be determined in units of milliamps.

(2) Your PM CPMS operating range must be capable of reading PM concentrations from zero to a level equivalent to at least two times your allowable emission limit. If your PM CPMS is an auto-ranging instrument capable of multiple scales, the primary range of the instrument must be capable of reading PM concentration from zero to a level equivalent to two times your allowable emission limit.

(3) During the initial performance test or any such subsequent performance test that demonstrates compliance with the PM limit, record and average all milliamp output values from the PM CPMS for the periods corresponding to the compliance test runs (e.g., average all your PM CPMS output values for three corresponding 2-hour Method 5I test runs).

(B) If the average of your three PM performance test runs are below 75 percent of your PM emission limit, you must calculate an operating limit by establishing a relationship of PM CPMS signal to PM concentration using the PM CPMS instrument zero, the average PM CPMS values corresponding to the three compliance test runs, and the average PM concentration from the Method 5 or performance test with the procedures in paragraphs (b)(4)(ii)(B)(1) through (4) of this section.

(1) Determine your instrument zero output with one of the following procedures:

(i) Zero point data for *in-situ* instruments should be obtained by removing the instrument from the stack and monitoring ambient air on a test bench.

(ii) Zero point data for *extractive* instruments should be obtained by removing the extractive probe from the stack and drawing in clean ambient air.



(iii) The zero point may also be established by performing manual reference method measurements when the flue gas is free of PM emissions or contains very low PM concentrations (e.g., when your process is not operating, but the fans are operating or your source is combusting only natural gas) and plotting these with the compliance data to find the zero intercept.

(iv) If none of the steps in paragraphs (b)(4)(ii)(B)(1)(i) through (iii) of this section are possible, you must use a zero output value provided by the manufacturer.

(2) Determine your PM CPMS instrument average in milliamps, and the average of your corresponding three PM compliance test runs, using equation 10.

$$\bar{x} = \frac{1}{n} \sum_{t=1}^n X_1 \bar{y} = \frac{1}{n} \sum_{t=1}^n Y_1 \quad (\text{Eq. 10})$$

Where:

$X_1$  = the PM CPMS data points for the three runs constituting the performance test,

$Y_1$  = the PM concentration value for the three runs constituting the performance test, and

$n$  = the number of data points.

(3) With your instrument zero expressed in milliamps, your three run average PM CPMS milliamp value, and your three run average PM concentration from your three compliance tests, determine a relationship of lb/MMBtu per milliamp with equation 11.

$$R = \frac{Y_1}{(X_1 - z)} \quad (\text{Eq. 11})$$

Where:

$R$  = the relative lb/MMBtu per milliamp for your PM CPMS,

$Y_1$  = the three run average lb/MMBtu PM concentration,

$X_1$  = the three run average milliamp output from you PM CPMS, and

$z$  = the milliamp equivalent of your instrument zero determined from (B)(i).

(4) Determine your source specific 30-day rolling average operating limit using the lb/MMBtu per milliamp value from Equation 11 in equation 12, below. This sets your operating limit at the PM CPMS output value corresponding to 75 percent of your emission limit.

$$O_l = z + \frac{0.75(L)}{R} \quad (\text{Eq. 12})$$

Where:

$O_l$  = the operating limit for your PM CPMS on a 30-day rolling average, in milliamps.

$L$  = your source emission limit expressed in lb/MMBtu,

$z$  = your instrument zero in milliamps, determined from (B)(i), and

$R$  = the relative lb/MMBtu per milliamp for your PM CPMS, from Equation 11.

(C) If the average of your three PM compliance test runs is at or above 75 percent of your PM emission limit you must determine your 30-day rolling average operating limit by averaging the PM CPMS milliamp output corresponding to your three PM performance test runs that demonstrate compliance with the emission limit using equation 13 and you must submit all compliance test and PM CPMS data according to the reporting requirements in paragraph (b)(4)(ii)(F) of this section.

$$O_h = \frac{1}{n} \sum_{t=1}^n X_1 \quad (\text{Eq. 13})$$

Where:

$X_1$  = the PM CPMS data points for all runs  $i$ ,

$n$  = the number of data points, and

$O_h$  = your site specific operating limit, in milliamps.

(D) To determine continuous compliance, you must record the PM CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (milliamps) on a 30-day rolling average basis, updated at the end of each new operating hour. Use Equation 14 to determine the 30-day rolling average.

$$30\text{-day} = \frac{\sum_{i=1}^n Hpv_i}{n} \quad (\text{Eq. 14})$$

Where:

30-day = 30-day average.

H<sub>pvi</sub> = is the hourly parameter value for hour i

n = is the number of valid hourly parameter values collected over the previous 30 operating days.

(E) Use EPA Method 5 of appendix A to part 60 of this chapter to determine PM emissions. For each performance test, conduct three separate runs under the conditions that exist when the affected source is operating at the highest load or capacity level reasonably expected to occur. Conduct each test run to collect a minimum sample volume specified in Table 1 or 2 or Tables 11 through 15 to this subpart, as applicable, for determining compliance with a new source limit or an existing source limit. Calculate the average of the results from three runs to determine compliance. You need not determine the PM collected in the impingers ("back half") of the Method 5 particulate sampling train to demonstrate compliance with the PM standards in this subpart. This shall not preclude the permitting authority from requiring a determination of the "back half" for other purposes.

(F) For PM performance test reports used to set a PM CPMS operating limit, the electronic submission of the test report must also include the make and model of the PM CPMS instrument, serial number of the instrument, analytical principle of the instrument (e.g. beta attenuation), span of the instruments primary analytical range, milliamp value equivalent to the instrument zero output, technique by which this zero value was determined, and the average milliamp signals corresponding to each PM compliance test run.

(iii) For a particulate wet scrubber, you must establish the minimum pressure drop and liquid flow rate as defined in § 63.7575, as your operating limits during the three-run performance test during which you demonstrate compliance with your applicable limit. If you use a wet scrubber and you conduct separate performance tests for PM and TSM emissions, you must establish one set of minimum scrubber liquid flow rate and pressure drop operating limits. If you conduct multiple performance tests, you must set the minimum liquid flow rate and pressure drop operating limits at the higher of the minimum values established during the performance tests.

(iv) For an electrostatic precipitator (ESP) operated with a wet scrubber, you must establish the minimum total secondary electric power input, as defined in § 63.7575, as your operating limit during the three-run performance test during which you demonstrate compliance with your applicable limit. (These operating limits do not apply to ESP that are operated as dry controls without a wet scrubber.)

(v) For a dry scrubber, you must establish the minimum sorbent injection rate for each sorbent, as defined in § 63.7575, as your operating limit during the three-run performance test during which you demonstrate compliance with your applicable limit.

(vi) For activated carbon injection, you must establish the minimum activated carbon injection rate, as defined in § 63.7575, as your operating limit during the three-run performance test during which you demonstrate compliance with your applicable limit.

(vii) The operating limit for boilers or process heaters with fabric filters that demonstrate continuous compliance through bag leak detection systems is that a bag leak detection system be installed according to the requirements in § 63.7525, and that each fabric filter must be operated such that the bag leak detection system alert is not activated more than 5 percent of the operating time during a 6-month period.

(viii) For a minimum oxygen level, if you conduct multiple performance tests, you must set the minimum oxygen level at the lower of the minimum values established during the performance tests.

(ix) The operating limit for boilers or process heaters that demonstrate continuous compliance with the HCl emission limit using a SO<sub>2</sub> CEMS is to install and operate the SO<sub>2</sub> according to the requirements in § 63.7525(m) establish a maximum SO<sub>2</sub> emission rate equal to the highest hourly average SO<sub>2</sub> measurement during the most recent three-run performance test for HCl.

(c) If you elect to demonstrate compliance with an applicable emission limit through fuel analysis, you must conduct fuel analyses according to § 63.7521 and follow the procedures in paragraphs (c)(1) through (5) of this section.

(1) If you burn more than one fuel type, you must determine the fuel mixture you could burn in your boiler or process heater that would result in the maximum emission rates of the pollutants that you elect to demonstrate compliance through fuel analysis.

(2) You must determine the 90th percentile confidence level fuel pollutant concentration of the composite samples analyzed for each fuel type using the one-sided t-statistic test described in Equation 15 of this section.

$$P90 = \text{mean} + (SD \times t) \quad (\text{Eq. 15})$$

Where:

P90 = 90th percentile confidence level pollutant concentration, in pounds per million Btu.

Mean = Arithmetic average of the fuel pollutant concentration in the fuel samples analyzed according to § 63.7521, in units of pounds per million Btu.

SD = Standard deviation of the mean of pollutant concentration in the fuel samples analyzed according to § 63.7521, in units of pounds per million Btu. SD is calculated as the sample standard deviation divided by the square root of the number of samples.

t = t distribution critical value for 90th percentile ( $t_{0.1}$ ) probability for the appropriate degrees of freedom (number of samples minus one) as obtained from a t-Distribution Critical Value Table.

(3) To demonstrate compliance with the applicable emission limit for HCl, the HCl emission rate that you calculate for your boiler or process heater using Equation 16 of this section must not exceed the applicable emission limit for HCl.

$$HCl = \sum_{i=1}^n (Ci90 \times Qi \times 1.028) \quad (\text{Eq. 16})$$

Where:

HCl = HCl emission rate from the boiler or process heater in units of pounds per million Btu.

Ci90 = 90th percentile confidence level concentration of chlorine in fuel type, i, in units of pounds per million Btu as calculated according to Equation 15 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of chlorine. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of "1" for Qi. For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of chlorine.

1.028 = Molecular weight ratio of HCl to chlorine.

(4) To demonstrate compliance with the applicable emission limit for mercury, the mercury emission rate that you calculate for your boiler or process heater using Equation 17 of this section must not exceed the applicable emission limit for mercury.

$$\text{Mercury} = \sum_{i=1}^n (\text{Hgi90} \times \text{Qi}) \quad (\text{Eq. 17})$$

Where:

Mercury = Mercury emission rate from the boiler or process heater in units of pounds per million Btu.

Hgi90 = 90th percentile confidence level concentration of mercury in fuel, i, in units of pounds per million Btu as calculated according to Equation 15 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest mercury content. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of "1" for Qi. For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest mercury content.

(5) To demonstrate compliance with the applicable emission limit for TSM for solid or liquid fuels, the TSM emission rate that you calculate for your boiler or process heater from solid fuels using Equation 18 of this section must not exceed the applicable emission limit for TSM.

$$\text{Metals} = \sum_{i=1}^n (\text{TSM90i} \times \text{Qi}) \quad (\text{Eq. 18})$$

Where:

Metals = TSM emission rate from the boiler or process heater in units of pounds per million Btu.

TSMi90 = 90th percentile confidence level concentration of TSM in fuel, i, in units of pounds per million Btu as calculated according to Equation 15 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest TSM content. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of "1" for Qi. For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest TSM content.

(d) [Reserved]

(e) You must include with the Notification of Compliance Status a signed certification that either the energy assessment was completed according to Table 3 to this subpart, and that the assessment is an accurate depiction of your facility at the time of the assessment, or that the maximum number of on-site technical hours specified in the definition of energy assessment applicable to the facility has been expended.

(f) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in § 63.7545(e).

(g) If you elect to demonstrate that a gaseous fuel meets the specifications of another gas 1 fuel as defined in § 63.7575, you must conduct an initial fuel specification analyses according to § 63.7521(f) through (i) and according to the frequency listed in § 63.7540(c) and maintain records of the results of the testing as outlined in § 63.7555(g). For samples where the initial mercury specification has not been exceeded, you will include a signed certification with the Notification of Compliance Status that the initial fuel specification test meets the gas specification outlined in the definition of other gas 1 fuels.

(h) If you own or operate a unit subject to emission limits in Table 1 or 2 or Tables 11 through 15 to this subpart, you must meet the work practice standard according to Table 3 to this subpart. During startup and shutdown, you must only follow the work practice standards according to items 5 and 6 of Table 3 to this subpart.

(i) If you opt to comply with the alternative SO<sub>2</sub> CEMS operating limit in Tables 4 and 8 to this subpart, you may do so only if your affected boiler or process heater:

(1) Has a system using wet scrubber or dry sorbent injection and SO<sub>2</sub> CEMS installed on the unit; and

(2) At all times, you operate the wet scrubber or dry sorbent injection for acid gas control on the unit consistent with § 63.7500(a)(3); and

(3) You establish a unit-specific maximum SO<sub>2</sub> operating limit by collecting the maximum hourly SO<sub>2</sub> emission rate on the SO<sub>2</sub> CEMS during the paired 3-run test for HCl. The maximum SO<sub>2</sub> operating limit is equal to the highest hourly average SO<sub>2</sub> concentration measured during the HCl performance test.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7174, Jan. 31, 2013; 80 FR 72811, Nov. 20, 2015; 87 FR 60845, Oct. 6, 2022]

**§ 63.7533 Can I use efficiency credits earned from implementation of energy conservation measures to comply with this subpart?**

(a) If you elect to comply with the alternative equivalent output-based emission limits, instead of the heat input-based limits listed in Table 2 or 15 to this subpart, and you want to take credit for implementing energy conservation measures identified in an energy assessment, you may demonstrate compliance using efficiency credits according to the procedures in this section. You may use this compliance approach for an existing affected boiler for demonstrating initial compliance according to § 63.7522(e) and for demonstrating monthly compliance according to § 63.7522(f). Owners or operators using this compliance approach must establish an emissions benchmark, calculate and document the efficiency credits, develop an Implementation Plan, comply with the general reporting requirements, and apply the efficiency credit according to the procedures in paragraphs (b) through (f) of this section. You cannot use this compliance approach for a new or reconstructed affected boiler. Additional guidance from the Department of Energy on efficiency credits is available at <https://www.epa.gov/ttn/atw/boiler/boilerpg.html>.

(b) For each existing affected boiler for which you intend to apply emissions credits, establish a benchmark from which emission reduction credits may be generated by determining the actual annual fuel heat input to the affected boiler before initiation of an energy conservation activity to reduce energy demand (*i.e.*, fuel usage) according to paragraphs (b)(1) through (4) of this section. The benchmark shall be expressed in trillion Btu per year heat input.

(1) The benchmark from which efficiency credits may be generated shall be determined by using the most representative, accurate, and reliable process available for the source. The benchmark shall be established for a one-year period before the date that an energy demand reduction occurs, unless it can be demonstrated that a different time period is more representative of historical operations.

(2) Determine the starting point from which to measure progress. Inventory all fuel purchased and generated on-site (off-gases, residues) in physical units (MMBtu, million cubic feet, etc.).

(3) Document all uses of energy from the affected boiler. Use the most recent data available.

(4) Collect non-energy related facility and operational data to normalize, if necessary, the benchmark to current operations, such as building size, operating hours, etc. If possible, use actual data that are current and timely rather than estimated data.

(c) Efficiency credits can be generated if the energy conservation measures were implemented after January 1, 2008 and if sufficient information is available to determine the appropriate value of credits.

(1) The following emission points cannot be used to generate efficiency credits:

(i) Energy conservation measures implemented on or before January 1, 2008, unless the level of energy demand reduction is increased after January 1, 2008, in which case credit will be allowed only for change in demand reduction achieved after January 1, 2008.

(ii) Efficiency credits on shut-down boilers. Boilers that are shut down cannot be used to generate credits unless the facility provides documentation linking the permanent shutdown to energy conservation measures identified in the energy assessment. In this case, the bench established for the affected boiler to which the credits from the shutdown will be applied must be revised to include the benchmark established for the shutdown boiler.

(2) For all points included in calculating emissions credits, the owner or operator shall:

(i) Calculate annual credits for all energy demand points. Use Equation 19 to calculate credits. Energy conservation measures that meet the criteria of paragraph (c)(1) of this section shall not be included, except as specified in paragraph (c)(1)(i) of this section.

(3) Credits are generated by the difference between the benchmark that is established for each affected boiler, and the actual energy demand reductions from energy conservation measures implemented after January 1, 2008. Credits shall be calculated using Equation 19 of this section as follows:

(i) The overall equation for calculating credits is:

$$ECredits = \left( \sum_{i=1}^n EIS_{iactual} \right) \div EI_{baseline} \quad (\text{Eq. 19})$$

Where:

ECredits = Energy Input Savings for all energy conservation measures implemented for an affected boiler, expressed as a decimal fraction of the baseline energy input.

EIS<sub>iactual</sub> = Energy Input Savings for each energy conservation measure, i, implemented for an affected boiler, million Btu per year.

EI<sub>baseline</sub> = Energy Input baseline for the affected boiler, million Btu per year.

n = Number of energy conservation measures included in the efficiency credit for the affected boiler.

(ii) [Reserved]

(d) The owner or operator shall develop, and submit for approval upon request by the Administrator, an Implementation Plan containing all of the information required in this paragraph for all boilers to be included in an efficiency credit approach. The Implementation Plan shall identify all existing affected boilers to be included in applying the efficiency credits. The Implementation Plan shall include a description of the energy conservation measures implemented and the energy savings generated from each measure and an explanation of the criteria

used for determining that savings. If requested, you must submit the implementation plan for efficiency credits to the Administrator for review and approval no later than 180 days before the date on which the facility intends to demonstrate compliance using the efficiency credit approach.

(e) The emissions rate as calculated using Equation 20 in paragraph (f) of this section from each existing boiler participating in the efficiency credit option must be in compliance with the limits in Table 2 or 15 to this subpart at all times the affected unit is subject to numeric emission limits, following the compliance date specified in § 63.7495.

(f) You must use Equation 20 of this paragraph (f) to demonstrate initial compliance by demonstrating that the emissions from the affected boiler participating in the efficiency credit compliance approach do not exceed the emission limits in Table 2 or 15 to this subpart.

## Equation 20 to paragraph (f)

$$E_{adj} = E_m \times (1 - ECredits) \quad (\text{Eq. 20})$$

Where:

$E_{adj}$  = Emission level adjusted by applying the efficiency credits earned, lb per million Btu steam output (or lb per MWh) for the affected boiler.

$E_m$  = Emissions measured during the performance test, lb per million Btu steam output (or lb per MWh) for the affected boiler.

ECredits = Efficiency credits from Equation 19 to paragraph (c)(3)(i) of this section for the affected boiler.

(g) As part of each compliance report submitted as required under § 63.7550, you must include documentation that the energy conservation measures implemented continue to generate the credit for use in demonstrating compliance with the emission limits.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7178, Jan. 31, 2013; 80 FR 72812, Nov. 20, 2015; 87 FR 60845, Oct. 6, 2022]

### Continuous Compliance Requirements

#### § 63.7535 Is there a minimum amount of monitoring data I must obtain?

(a) You must monitor and collect data according to this section and the site-specific monitoring plan required by § 63.7505(d).

(b) You must operate the monitoring system and collect data at all required intervals at all times that each boiler or process heater is operating and compliance is required, except for periods of monitoring system malfunctions or out of control periods (see § 63.8(c)(7) of this part), and required monitoring system quality assurance or control activities, including, as applicable, calibration checks, required zero and span adjustments, and scheduled CMS maintenance as defined in your site-specific monitoring plan. A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. You are required to complete monitoring system repairs in response to monitoring system malfunctions or out-of-control periods and to return the monitoring system to operation as expeditiously as practicable.



(c) You may not use data recorded during periods of startup and shutdown, monitoring system malfunctions or out-of-control periods, repairs associated with monitoring system malfunctions or out-of-control periods, or required monitoring system quality assurance or control activities in data averages and calculations used to report emissions or operating levels. You must record and make available upon request results of CMS performance audits and dates and duration of periods when the CMS is out of control to completion of the corrective actions necessary to return the CMS to operation consistent with your site-specific monitoring plan. You must use all the data collected during all other periods in assessing compliance and the operation of the control device and associated control system.

(d) Except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits, calibration checks, and required zero and span adjustments), failure to collect required data is a deviation of the monitoring requirements. In calculating monitoring results, do not use any data collected during periods of startup and shutdown, when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities. You must calculate monitoring results using all other monitoring data collected while the process is operating. You must report all periods when the monitoring system is out of control in your semi-annual report.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7179, Jan. 31, 2013; 80 FR 72812, Nov. 20, 2015]

**§ 63.7540 How do I demonstrate continuous compliance with the emission limitations, fuel specifications and work practice standards?**

(a) You must demonstrate continuous compliance with each emission limit in Tables 1 and 2 or 11 through 15 to this subpart, the work practice standards in Table 3 to this subpart, and the operating limits in Table 4 to this subpart that applies to you according to the methods specified in Table 8 to this subpart and paragraphs (a)(1) through (19) of this section.

(1) Following the date on which the initial compliance demonstration is completed or is required to be completed under §§ 63.7 and 63.7510, whichever date comes first, operation above the established maximum or below the established minimum operating limits shall constitute a deviation of established operating limits listed in Table 4 of this subpart except during performance tests conducted to determine compliance with the emission limits or to establish new operating limits. Operating limits must be confirmed or reestablished during performance tests.

(2) As specified in § 63.7555(d), you must keep records of the type and amount of all fuels burned in each boiler or process heater during the reporting period to demonstrate that all fuel types and mixtures of fuels burned would result in either of the following:

(i) Equal to or lower emissions of HCl, mercury, and TSM than the applicable emission limit for each pollutant, if you demonstrate compliance through fuel analysis.

(ii) Equal to or lower fuel input of chlorine, mercury, and TSM than the maximum values calculated during the last performance test, if you demonstrate compliance through performance testing.

(3) If you demonstrate compliance with an applicable HCl emission limit through fuel analysis for a solid or liquid fuel and you plan to burn a new type of solid or liquid fuel, you must recalculate the HCl emission rate using Equation 16 of § 63.7530 according to paragraphs (a)(3)(i) through (iii) of this section. You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the HCl emission rate.

(i) You must determine the chlorine concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to § 63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of chlorine.

(iii) Recalculate the HCl emission rate from your boiler or process heater under these new conditions using Equation 16 of § 63.7530. The recalculated HCl emission rate must be less than the applicable emission limit.

(4) If you demonstrate compliance with an applicable HCl emission limit through performance testing and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum chlorine input using Equation 7 of § 63.7530. If the results of recalculating the maximum chlorine input using Equation 7 of § 63.7530 are greater than the maximum chlorine input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in § 63.7520 to demonstrate that the HCl emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in § 63.7530(b). In recalculating the maximum chlorine input and establishing the new operating limits, you are not required to conduct fuel analyses for and include the fuels described in § 63.7510(a)(2)(i) through (iii).

(5) If you demonstrate compliance with an applicable mercury emission limit through fuel analysis, and you plan to burn a new type of fuel, you must recalculate the mercury emission rate using Equation 17 of § 63.7530 according to the procedures specified in paragraphs (a)(5)(i) through (iii) of this section. You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the mercury emission rate.

(i) You must determine the mercury concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to § 63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of mercury.

(iii) Recalculate the mercury emission rate from your boiler or process heater under these new conditions using Equation 17 of § 63.7530. The recalculated mercury emission rate must be less than the applicable emission limit.

(6) If you demonstrate compliance with an applicable mercury emission limit through performance testing, and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum mercury input using Equation 8 of § 63.7530. If the results of recalculating the maximum mercury input using Equation 8 of § 63.7530 are higher than the maximum mercury input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in § 63.7520 to demonstrate that the mercury emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in § 63.7530(b). You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the mercury emission rate.

(7) If your unit is controlled with a fabric filter, and you demonstrate continuous compliance using a bag leak detection system, you must initiate corrective action within 1 hour of a bag leak detection system alert and complete corrective actions as soon as practical, and operate and maintain the fabric filter system such that the periods which would cause an alert are no more than 5 percent of the operating time during a 6-month period. You must also keep records of the date, time, and duration of each alert, the time corrective action was initiated and completed, and a brief description of the cause of the alert and the corrective action taken. You must also record the percent of the operating time during each 6-month period that the conditions exist for an alert. In calculating this operating time percentage, if inspection of the fabric filter demonstrates that no corrective action is required, no alert time is counted. If corrective action is required, each alert shall be counted as a minimum of 1 hour. If you take longer than 1 hour to initiate corrective action, the alert time shall be counted as the actual amount of time taken to initiate corrective action.

(8) To demonstrate compliance with the applicable alternative CO CEMS emission limit listed in Table 1 or 2 or Tables 11 through 15 to this subpart, you must meet the requirements in paragraphs (a)(8)(i) through (iv) of this section.

(i) Continuously monitor CO according to §§ 63.7525(a) and 63.7535.

(ii) Maintain a CO emission level below or at your applicable alternative CO CEMS-based standard in Table 1 or 2 or Tables 11 through 15 to this subpart at all times the affected unit is subject to numeric emission limits.

(iii) Keep records of CO levels according to § 63.7555(b).

(iv) You must record and make available upon request results of CO CEMS performance audits, dates and duration of periods when the CO CEMS is out of control to completion of the corrective actions necessary to return the CO CEMS to operation consistent with your site-specific monitoring plan.

(9) The owner or operator of a boiler or process heater using a PM CPMS or a PM CEMS to meet requirements of this subpart shall install, certify (PM CEMS only), operate, and maintain the PM CPMS or PM CEMS in accordance with your site-specific monitoring plan as required in § 63.7505(d).

(10) If your boiler or process heater has a heat input capacity of 10 million Btu per hour or greater, you must conduct an annual tune-up of the boiler or process heater to demonstrate continuous compliance as specified in paragraphs (a)(10)(i) through (vi) of this section. You must conduct the tune-up while burning the type of fuel (or fuels in case of units that routinely burn a mixture) that provided the majority of the heat input to the boiler or process heater over the 12 months prior to the tune-up. This frequency does not apply to limited-use boilers and process heaters, as defined in § 63.7575, or units with continuous oxygen trim systems that maintain an optimum air to fuel ratio.

(i) As applicable, inspect the burner, and clean or replace any components of the burner as necessary (you may perform the burner inspection any time prior to the tune-up or delay the burner inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the burner inspection until the first outage, not to exceed 36 months from the previous inspection. At units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or process equipment;

(ii) Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available;

(iii) Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (you may delay the inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the inspection until the first outage, not to exceed 36 months from the previous inspection;

(iv) Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any NO<sub>x</sub> requirement to which the unit is subject;

(v) Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). Measurements may be taken using a portable CO analyzer; and

(vi) Maintain on-site and submit, if requested by the Administrator, a report containing the information in paragraphs (a)(10)(vi)(A) through (C) of this section,

(A) The concentrations of CO in the effluent stream in parts per million by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler or process heater;

(B) A description of any corrective actions taken as a part of the tune-up; and

(C) The type and amount of fuel used over the 12 months prior to the tune-up, but only if the unit was physically and legally capable of using more than one type of fuel during that period. Units sharing a fuel meter may estimate the fuel used by each unit.

(11) If your boiler or process heater has a heat input capacity of less than 10 million Btu per hour (except as specified in paragraph (a)(12) of this section), you must conduct a biennial tune-up of the boiler or process heater as specified in paragraphs (a)(10)(i) through (vi) of this section to demonstrate continuous compliance.

(12) If your boiler or process heater has a continuous oxygen trim system that maintains an optimum air to fuel ratio, or a heat input capacity of less than or equal to 5 million Btu per hour and the unit is in the units designed to burn gas 1; units designed to burn gas 2 (other); or units designed to burn light liquid subcategories, or meets the definition of limited-use boiler or process heater in § 63.7575, you must conduct a tune-up of the boiler or process heater every 5 years as specified in paragraphs (a)(10)(i) through (vi) of this section to demonstrate continuous compliance. You may delay the burner inspection specified in paragraph (a)(10)(i) of this section until the next scheduled or unscheduled unit shutdown, but you must inspect each burner at least once every 72 months. If an oxygen trim system is utilized on a unit without emission standards to reduce the tune-up frequency to once every 5 years, set the oxygen level no lower than the oxygen concentration measured during the most recent tune-up.

(13) If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 calendar days of startup.

(14) If you are using a CEMS measuring mercury emissions to meet requirements of this subpart you must install, certify, operate, and maintain the mercury CEMS as specified in paragraphs (a)(14)(i) and (ii) of this section.

(i) Operate the mercury CEMS in accordance with performance specification 12A of 40 CFR part 60, appendix B or operate a sorbent trap based integrated monitor in accordance with performance specification 12B of 40 CFR part 60, appendix B. The duration of the performance test must be 30 operating days if you specified a 30 operating day basis in § 63.7545(e)(2)(iii) for mercury CEMS or it must be 720 hours if you specified a 720 hour basis in § 63.7545(e)(2)(iii) for mercury CEMS. For each day in which the unit operates, you must obtain hourly mercury concentration data, and stack gas volumetric flow rate data.

(ii) If you are using a mercury CEMS, you must install, operate, calibrate, and maintain an instrument for continuously measuring and recording the mercury mass emissions rate to the atmosphere according to the requirements of performance specifications 6 and 12A of 40 CFR part 60, appendix B, and quality assurance procedure 6 of 40 CFR part 60, appendix F.

(15) If you are using a CEMS to measure HCl emissions to meet requirements of this subpart, you must install, certify, operate, and maintain the HCl CEMS as specified in paragraphs (a)(15)(i) and (ii) of this section. This option for an affected unit takes effect on the date of approval of a site-specific monitoring plan.

(i) Operate the continuous emissions monitoring system in accordance with the applicable performance specification in 40 CFR part 60, appendix B. The duration of the performance test must be 30 operating days if you specified a 30 operating day basis in § 63.7545(e)(2)(iii) for HCl CEMS or it must be 720 hours if you specified a 720 hour basis in § 63.7545(e)(2)(iii) for HCl CEMS. For each day in which the unit operates, you must obtain hourly HCl concentration data, and stack gas volumetric flow rate data.

(ii) If you are using a HCl CEMS, you must install, operate, calibrate, and maintain an instrument for continuously measuring and recording the HCl mass emissions rate to the atmosphere according to the requirements of the applicable performance specification of 40 CFR part 60, appendix B, and the quality assurance procedures of 40 CFR part 60, appendix F.

(16) If you demonstrate compliance with an applicable TSM emission limit through performance testing, and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum TSM input using Equation 9 of § 63.7530. If the results of recalculating the maximum TSM input using Equation 9 of § 63.7530 are higher than the maximum total selected input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in § 63.7520 to demonstrate that the TSM emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in § 63.7530(b). You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the TSM emission rate.

(17) If you demonstrate compliance with an applicable TSM emission limit through fuel analysis for solid or liquid fuels, and you plan to burn a new type of fuel, you must recalculate the TSM emission rate using Equation 18 of § 63.7530 according to the procedures specified in paragraphs (a)(5)(i) through (iii) of this section. You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the TSM emission rate.

(i) You must determine the TSM concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to § 63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of TSM.

(iii) Recalculate the TSM emission rate from your boiler or process heater under these new conditions using Equation 18 of § 63.7530. The recalculated TSM emission rate must be less than the applicable emission limit.

(18) If you demonstrate continuous PM emissions compliance with a PM CPMS you will use a PM CPMS to establish a site-specific operating limit corresponding to the results of the performance test demonstrating compliance with the PM limit. You will conduct your performance test using the test method criteria in Table 5 of this subpart. You will use the PM CPMS to demonstrate continuous compliance with this operating limit. You must repeat the performance test annually and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(i) To determine continuous compliance, you must record the PM CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (milliamps) on a 30-day rolling average basis.

(ii) For any deviation of the 30-day rolling PM CPMS average value from the established operating parameter limit, you must:

(A) Within 48 hours of the deviation, visually inspect the air pollution control device (APCD);

(B) If inspection of the APCD identifies the cause of the deviation, take corrective action as soon as possible and return the PM CPMS measurement to within the established value; and

(C) Within 30 days of the deviation or at the time of the annual compliance test, whichever comes first, conduct a PM emissions compliance test to determine compliance with the PM emissions limit and to verify or re-establish the CPMS operating limit. You are not required to conduct additional testing for any deviations that occur between the time of the original deviation and the PM emissions compliance test required under this paragraph.

(iii) PM CPMS deviations from the operating limit leading to more than four required performance tests in a 12-month operating period constitute a separate violation of this subpart.

(19) If you choose to comply with the PM filterable emissions limit by using PM CEMS you must install, certify, operate, and maintain a PM CEMS and record the output of the PM CEMS as specified in paragraphs (a)(19)(i) through (vii) of this section. The compliance limit will be expressed as a 30-day rolling average of the numerical emissions limit value applicable for your unit in Table 1 or 2 or Tables 11 through 15 to this subpart.

(i) Install and certify your PM CEMS according to the procedures and requirements in Performance Specification 11 - Specifications and Test Procedures for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix B to part 60 of this chapter, using test criteria outlined in Table V of this rule. The reportable measurement output from the PM CEMS must be expressed in units of the applicable emissions limit (e.g., lb/MMBtu, lb/MWh).

(ii) Operate and maintain your PM CEMS according to the procedures and requirements in Procedure 2 - Quality Assurance Requirements for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix F to part 60 of this chapter.

(A) You must conduct the relative response audit (RRA) for your PM CEMS at least once annually.

(B) You must conduct the relative correlation audit (RCA) for your PM CEMS at least once every 3 years.

(iii) Collect PM CEMS hourly average output data for all boiler operating hours except as indicated in paragraph (v) of this section.

(iv) Calculate the arithmetic 30-day rolling average of all of the hourly average PM CEMS output data collected during all nonexempt boiler or process heater operating hours.

(v) You must collect data using the PM CEMS at all times the unit is operating and at the intervals specified in this paragraph (a), except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities.

(vi) You must use all the data collected during all boiler or process heater operating hours in assessing the compliance with your operating limit except:

(A) Any data collected during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities conducted during monitoring system malfunctions in calculations and report any such periods in your annual deviation report;

(B) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or control activities conducted during out of control periods in calculations used to report emissions or operating levels and report any such periods in your annual deviation report;

(C) Any data recorded during periods of startup or shutdown.

(vii) You must record and make available upon request results of PM CEMS system performance audits, dates and duration of periods when the PM CEMS is out of control to completion of the corrective actions necessary to return the PM CEMS to operation consistent with your site-specific monitoring plan.

(b) You must report each instance in which you did not meet each emission limit and operating limit in Tables 1 through 4 or 11 through 15 to this subpart that apply to you. These instances are deviations from the emission limits or operating limits, respectively, in this subpart. These deviations must be reported according to the requirements in § 63.7550.

(c) If you elected to demonstrate that the unit meets the specification for mercury for the unit designed to burn gas 1 subcategory, you must follow the sampling frequency specified in paragraphs (c)(1) through (4) of this section and conduct this sampling according to the procedures in § 63.7521(f) through (i).

(1) If the initial mercury constituents in the gaseous fuels are measured to be equal to or less than half of the mercury specification as defined in § 63.7575, you do not need to conduct further sampling.

(2) If the initial mercury constituents are greater than half but equal to or less than 75 percent of the mercury specification as defined in § 63.7575, you will conduct semi-annual sampling. If 6 consecutive semi-annual fuel analyses demonstrate 50 percent or less of the mercury specification, you do not need to conduct further sampling. If any semi-annual sample exceeds 75 percent of the mercury specification, you must return to monthly sampling for that fuel, until 12 months of fuel analyses again are less than 75 percent of the compliance level.

(3) If the initial mercury constituents are greater than 75 percent of the mercury specification as defined in § 63.7575, you will conduct monthly sampling. If 12 consecutive monthly fuel analyses demonstrate 75 percent or less of the mercury specification, you may decrease the fuel analysis frequency to semi-annual for that fuel.

(4) If the initial sample exceeds the mercury specification as defined in § 63.7575, each affected boiler or process heater combusting this fuel is not part of the unit designed to burn gas 1 subcategory and must be in compliance with the emission and operating limits for the appropriate subcategory. You may elect to conduct additional monthly sampling while complying with these emissions and operating limits to demonstrate that the fuel qualifies as another gas 1 fuel. If 12 consecutive monthly fuel analyses samples are at or below the mercury specification as defined in § 63.7575, each affected boiler or process heater combusting the fuel can elect to switch back into the unit designed to burn gas 1 subcategory until the mercury specification is exceeded.

(d) For startup and shutdown, you must meet the work practice standards according to items 5 and 6 of Table 3 of this subpart.

[78 FR 7179, Jan. 31, 2013, as amended at 80 FR 72813, Nov. 20, 2015; 87 FR 60846, Oct. 6, 2022]

**§ 63.7541 How do I demonstrate continuous compliance under the emissions averaging provision?**

(a) Following the compliance date, the owner or operator must demonstrate compliance with this subpart on a continuous basis by meeting the requirements of paragraphs (a)(1) through (5) of this section.

(1) For each calendar month, demonstrate compliance with the average weighted emissions limit for the existing units participating in the emissions averaging option as determined in § 63.7522(f) and (g).

(2) You must maintain the applicable opacity limit according to paragraphs (a)(2)(i) and (ii) of this section.

(i) For each existing unit participating in the emissions averaging option that is equipped with a dry control system and not vented to a common stack, maintain opacity at or below the applicable limit.

(ii) For each group of units participating in the emissions averaging option where each unit in the group is equipped with a dry control system and vented to a common stack that does not receive emissions from non-affected units, maintain opacity at or below the applicable limit at the common stack.

(3) For each existing unit participating in the emissions averaging option that is equipped with a wet scrubber, maintain the 30-day rolling average parameter values at or above the operating limits established during the most recent performance test.

(4) For each existing unit participating in the emissions averaging option that has an approved alternative operating parameter, maintain the 30-day rolling average parameter values consistent with the approved monitoring plan.

(5) For each existing unit participating in the emissions averaging option venting to a common stack configuration containing affected units from other subcategories, maintain the appropriate operating limit for each unit as specified in Table 4 to this subpart that applies.

(b) Any instance where the owner or operator fails to comply with the continuous monitoring requirements in paragraphs (a)(1) through (5) of this section is a deviation.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7182, Jan. 31, 2013]

## Notification, Reports, and Records

### § 63.7545 What notifications must I submit and when?

(a) You must submit to the Administrator all of the notifications in §§ 63.7(b) and (c), 63.8(e), (f)(4) and (6), and 63.9(b) through (h) that apply to you by the dates specified.

(b) As specified in § 63.9(b)(2), if you startup your affected source before January 31, 2013, you must submit an Initial Notification not later than 120 days after January 31, 2013, or no later than 120 days after the source becomes subject to this subpart, whichever is later.

(c) As specified in § 63.9(b)(4) and (5), if you startup your new or reconstructed affected source on or after January 31, 2013, you must submit an Initial Notification not later than 15 days after the actual date of startup of the affected source. For a new or reconstructed affected source that has reclassified to major source status, you must submit an Initial Notification not later 120 days after the source becomes subject to this subpart.

(d) If you are required to conduct a performance test you must submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin.

(e) If you are required to conduct an initial compliance demonstration as specified in § 63.7530, you must submit a Notification of Compliance Status according to § 63.9(h)(2)(ii). For the initial compliance demonstration for each boiler or process heater, you must submit the Notification of Compliance Status, including all performance test results and fuel analyses, before the close of business on the 60th day following the completion of all performance test and/or other initial compliance demonstrations for all boiler or process heaters at the facility according to § 63.10(d)(2). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1) through (8) of this section, as applicable. If you are not required to conduct an initial compliance demonstration as specified in § 63.7530(a), the Notification of Compliance Status must only contain the information specified in paragraphs (e)(1) and (8) of this section and must be submitted within 60 days of the compliance date specified at § 63.7495(b).

(1) A description of the affected unit(s) including identification of which subcategories the unit is in, the design heat input capacity of the unit, a description of the add-on controls used on the unit to comply with this subpart, description of the fuel(s) burned, including whether the fuel(s) were a secondary material determined by you or the EPA through a petition process to be a non-waste under § 241.3 of this chapter, whether the fuel(s) were a secondary material processed from discarded non-hazardous secondary materials within the meaning of § 241.3 of this chapter, and justification for the selection of fuel(s) burned during the compliance demonstration.

(2) Summary of the results of all performance tests and fuel analyses, and calculations conducted to demonstrate initial compliance including all established operating limits, and including:

(i) Identification of whether you are complying with the PM emission limit or the alternative TSM emission limit.

(ii) Identification of whether you are complying with the output-based emission limits or the heat input-based (i.e., lb/MMBtu or ppm) emission limits,

(iii) Identification of whether you are complying the arithmetic mean of all valid hours of data from the previous 30 operating days or of the previous 720 hours. This identification shall be specified separately for each operating parameter.

(3) A summary of the maximum CO emission levels recorded during the performance test to show that you have met any applicable emission standard in Table 1 or 2 or Tables 11 through 15 to this subpart, if you are not using a CO CEMS to demonstrate compliance.

(4) Identification of whether you plan to demonstrate compliance with each applicable emission limit through performance testing, a CEMS, or fuel analysis.



(5) Identification of whether you plan to demonstrate compliance by emissions averaging and identification of whether you plan to demonstrate compliance by using efficiency credits through energy conservation:

(i) If you plan to demonstrate compliance by emission averaging, report the emission level that was being achieved or the control technology employed on January 31, 2013.

(ii) [Reserved]

(6) A signed certification that you have met all applicable emission limits and work practice standards.

(7) If you had a deviation from any emission limit, work practice standard, or operating limit, you must also submit a description of the deviation, the duration of the deviation, and the corrective action taken in the Notification of Compliance Status report.

(8) In addition to the information required in § 63.9(h)(2), your notification of compliance status must include the following certification(s) of compliance, as applicable, and signed by a responsible official:

(i) "This facility completed the required initial tune-up for all of the boilers and process heaters covered by 40 CFR part 63 subpart DDDDD at this site according to the procedures in § 63.7540(a)(10)(i) through (vi)."

(ii) "This facility has had an energy assessment performed according to § 63.7530(e)."

(iii) Except for units that burn only natural gas, refinery gas, or other gas 1 fuel, or units that qualify for a statutory exemption as provided in section 129(g)(1) of the Clean Air Act, include the following: "No secondary materials that are solid waste were combusted in any affected unit."

(f) If you operate a unit designed to burn natural gas, refinery gas, or other gas 1 fuels that is subject to this subpart, and you intend to use a fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart of this part, part 60, 61, or 65, or other gas 1 fuel to fire the affected unit during a period of natural gas curtailment or supply interruption, as defined in § 63.7575, you must submit a notification of alternative fuel use within 48 hours of the declaration of each period of natural gas curtailment or supply interruption, as defined in § 63.7575. The notification must include the information specified in paragraphs (f)(1) through (5) of this section.

(1) Company name and address.

(2) Identification of the affected unit.

(3) Reason you are unable to use natural gas or equivalent fuel, including the date when the natural gas curtailment was declared or the natural gas supply interruption began.

(4) Type of alternative fuel that you intend to use.

(5) Dates when the alternative fuel use is expected to begin and end.

(g) If you intend to commence or recommence combustion of solid waste, you must provide 30 days prior notice of the date upon which you will commence or recommence combustion of solid waste. The notification must identify:

(1) The name of the owner or operator of the affected source, as defined in § 63.7490, the location of the source, the boiler(s) or process heater(s) that will commence burning solid waste, and the date of the notice.

(2) The currently applicable subcategories under this subpart.

(3) The date on which you became subject to the currently applicable emission limits.

(4) The date upon which you will commence combusting solid waste.

(h) If you have switched fuels or made a physical change to the boiler or process heater and the fuel switch or physical change resulted in the applicability of a different subcategory, you must provide notice of the date upon which you switched fuels or made the physical change within 30 days of the switch/change. The notification must identify:

- (1) The name of the owner or operator of the affected source, as defined in § 63.7490, the location of the source, the boiler(s) and process heater(s) that have switched fuels, were physically changed, and the date of the notice.
- (2) The currently applicable subcategory under this subpart.
- (3) The date upon which the fuel switch or physical change occurred.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7183, Jan. 31, 2013; 80 FR 72814, Nov. 20, 2015; 85 FR 73913, Nov. 19, 2020; 85 FR 84262, Dec. 28, 2020; 87 FR 60846, Oct. 6, 2022]

**§ 63.7550 What reports must I submit and when?**

(a) You must submit each report in Table 9 to this subpart that applies to you.

(b) Unless the EPA Administrator has approved a different schedule for submission of reports under § 63.10(a), you must submit each report, according to paragraph (h) of this section, by the date in Table 9 to this subpart and according to the requirements in paragraphs (b)(1) through (4) of this section. For units that are subject only to a requirement to conduct subsequent annual, biennial, or 5-year tune-up according to § 63.7540(a)(10), (11), or (12), respectively, and not subject to emission limits or Table 4 operating limits, you may submit only an annual, biennial, or 5-year compliance report, as applicable, as specified in paragraphs (b)(1) through (4) of this section, instead of a semi-annual compliance report.

(1) The first semi-annual compliance report must cover the period beginning on the compliance date that is specified for each boiler or process heater in § 63.7495 and ending on June 30 or December 31, whichever date is the first date that occurs at least 180 days after the compliance date that is specified for your source in § 63.7495. If submitting an annual, biennial, or 5-year compliance report, the first compliance report must cover the period beginning on the compliance date that is specified for each boiler or process heater in § 63.7495 and ending on December 31 within 1, 2, or 5 years, as applicable, after the compliance date that is specified for your source in § 63.7495.

(2) The first semi-annual compliance report must be postmarked or submitted no later than July 31 or January 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for each boiler or process heater in § 63.7495. The first annual, biennial, or 5-year compliance report must be postmarked or submitted no later than January 31.

(3) Each subsequent semi-annual compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31. Annual, biennial, and 5-year compliance reports must cover the applicable 1-, 2-, or 5-year periods from January 1 to December 31.

(4) Each subsequent semi-annual compliance report must be postmarked or submitted no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period. Annual, biennial, and 5-year compliance reports must be postmarked or submitted no later than January 31.

(5) For each affected source that is subject to permitting regulations pursuant to part 70 or part 71 of this chapter, and if the permitting authority has established dates for submitting semiannual reports pursuant to 70.6(a)(3)(iii)(A) or 71.6(a)(3)(iii)(A), you may submit the first and subsequent compliance reports according to the dates the permitting authority has established in the permit instead of according to the dates in paragraphs (b)(1) through (4) of this section.

(c) A compliance report must contain the following information depending on how the facility chooses to comply with the limits set in this rule.

- (1) If the facility is subject to the requirements of a tune up you must submit a compliance report with the information in paragraphs (c)(5)(i) through (iii) of this section, (xiv) and (xvii) of this section, and paragraph (c)(5)(iv) of this section for limited-use boiler or process heater.
- (2) If you are complying with the fuel analysis you must submit a compliance report with the information in paragraphs (c)(5)(i) through (iii), (vi), (x), (xi), (xiii), (xv), (xvii), (xviii) and paragraph (d) of this section.
- (3) If you are complying with the applicable emissions limit with performance testing you must submit a compliance report with the information in (c)(5)(i) through (iii), (vi), (vii), (viii), (ix), (xi), (xiii), (xv), (xvii), (xviii) and paragraph (d) of this section.
- (4) If you are complying with an emissions limit using a CMS the compliance report must contain the information required in paragraphs (c)(5)(i) through (iii), (v), (vi), (xi) through (xiii), (xv) through (xviii), and paragraph (e) of this section.
- (5)
  - (i) Company and Facility name and address.
  - (ii) Process unit information, emissions limitations, and operating parameter limitations.
  - (iii) Date of report and beginning and ending dates of the reporting period.
  - (iv) The total operating time during the reporting period.
  - (v) If you use a CMS, including CEMS, COMS, or CPMS, you must include the monitoring equipment manufacturer(s) and model numbers and the date of the last CMS certification or audit.
  - (vi) The total fuel use by each individual boiler or process heater subject to an emission limit within the reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by the EPA or your basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure.
  - (vii) If you are conducting performance tests once every 3 years consistent with § 63.7515(b) or (c), the date of the last 2 performance tests and a statement as to whether there have been any operational changes since the last performance test that could increase emissions.
  - (viii) A statement indicating that you burned no new types of fuel in an individual boiler or process heater subject to an emission limit. Or, if you did burn a new type of fuel and are subject to a HCl emission limit, you must submit the calculation of chlorine input, using Equation 7 of § 63.7530, that demonstrates that your source is still within its maximum chlorine input level established during the previous performance testing (for sources that demonstrate compliance through performance testing) or you must submit the calculation of HCl emission rate using Equation 16 of § 63.7530 that demonstrates that your source is still meeting the emission limit for HCl emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel and are subject to a mercury emission limit, you must submit the calculation of mercury input, using Equation 8 of § 63.7530, that demonstrates that your source is still within its maximum mercury input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of mercury emission rate using Equation 17 of § 63.7530 that demonstrates that your source is still meeting the emission limit for mercury emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel and are subject to a TSM emission limit, you must submit the calculation of TSM input, using Equation 9 of § 63.7530, that demonstrates that your source is still within its maximum TSM input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of TSM emission rate, using Equation 18 of § 63.7530, that demonstrates that your source is still meeting the emission limit for TSM emissions (for boilers or process heaters that demonstrate compliance through fuel analysis).

- (ix) If you wish to burn a new type of fuel in an individual boiler or process heater subject to an emission limit and you cannot demonstrate compliance with the maximum chlorine input operating limit using Equation 7 of § 63.7530 or the maximum mercury input operating limit using Equation 8 of § 63.7530, or the maximum TSM input operating limit using Equation 9 of § 63.7530 you must include in the compliance report a statement indicating the intent to conduct a new performance test within 60 days of starting to burn the new fuel.
- (x) A summary of any monthly fuel analyses conducted to demonstrate compliance according to §§ 63.7521 and 63.7530 for individual boilers or process heaters subject to emission limits, and any fuel specification analyses conducted according to §§ 63.7521(f) and 63.7530(g).
- (xi) If there are no deviations from any emission limits or operating limits in this subpart that apply to you, a statement that there were no deviations from the emission limits or operating limits during the reporting period.
- (xii) If there were no deviations from the monitoring requirements including no periods during which the CMSs, including CEMS, COMS, and CPMS, were out of control as specified in § 63.8(c)(7), a statement that there were no deviations and no periods during which the CMS were out of control during the reporting period.
- (xiii) If a malfunction occurred during the reporting period, the report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by you during a malfunction of a boiler, process heater, or associated air pollution control device or CMS to minimize emissions in accordance with § 63.7500(a)(3), including actions taken to correct the malfunction.
- (xiv) Include the date of the most recent tune-up for each unit subject to only the requirement to conduct an annual, biennial, or 5-year tune-up according to § 63.7540(a)(10), (11), or (12) respectively. Include the date of the most recent burner inspection if it was not done annually, biennially, or on a 5-year period and was delayed until the next scheduled or unscheduled unit shutdown.
- (xv) If you plan to demonstrate compliance by emission averaging, certify the emission level achieved or the control technology employed is no less stringent than the level or control technology contained in the notification of compliance status in § 63.7545(e)(5)(i).
- (xvi) For each reporting period, the compliance reports must include all of the calculated 30 day rolling average values for CEMS (CO, HCl, SO<sub>2</sub>, and mercury), 10 day rolling average values for CO CEMS when the limit is expressed as a 10 day instead of 30 day rolling average, and the PM CPMS data.
- (xvii) Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report.
- (xviii) For each instance of startup or shutdown include the information required to be monitored, collected, or recorded according to the requirements of § 63.7555(d).
- (d) For each deviation from an emission limit or operating limit in this subpart that occurs at an individual boiler or process heater where you are not using a CMS to comply with that emission limit or operating limit, or from the work practice standards for periods of startup and shutdown, the compliance report must additionally contain the information required in paragraphs (d)(1) through (3) of this section.
- (1) A description of the deviation and which emission limit, operating limit, or work practice standard from which you deviated.
- (2) Information on the number, duration, and cause of deviations (including unknown cause), as applicable, and the corrective action taken.
- (3) If the deviation occurred during an annual performance test, provide the date the annual performance test was completed.

(e) For each deviation from an emission limit, operating limit, and monitoring requirement in this subpart occurring at an individual boiler or process heater where you are using a CMS to comply with that emission limit or operating limit, the compliance report must additionally contain the information required in paragraphs (e)(1) through (9) of this section. This includes any deviations from your site-specific monitoring plan as required in § 63.7505(d).

(1) The date and time that each deviation started and stopped and description of the nature of the deviation (i.e., what you deviated from).

(2) The date and time that each CMS was inoperative, except for zero (low-level) and high-level checks.

(3) The date, time, and duration that each CMS was out of control, including the information in § 63.8(c)(8).

(4) The date and time that each deviation started and stopped.

(5) A summary of the total duration of the deviation during the reporting period and the total duration as a percent of the total source operating time during that reporting period.

(6) A characterization of the total duration of the deviations during the reporting period into those that are due to control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of CMS's downtime during the reporting period and the total duration of CMS downtime as a percent of the total source operating time during that reporting period.

(8) A brief description of the source for which there was a deviation.

(9) A description of any changes in CMSs, processes, or controls since the last reporting period for the source for which there was a deviation.

(f)-(g) [Reserved]

(h) You must submit the reports according to the procedures specified in paragraphs (h)(1) through (3) of this section.

(1) Within 60 days after the date of completing each performance test (as defined in § 63.2) required by this subpart, you must submit the results of the performance tests, including any fuel analyses, following the procedure specified in either paragraph (h)(1)(i) or (ii) of this section.

(i) For data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT Web site (<http://www.epa.gov/ttn/chief/ert/index.html>), you must submit the results of the performance test to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (<https://cdx.epa.gov/>.) Performance test data must be submitted in a file format generated through use of the EPA's ERT or an electronic file format consistent with the extensible markup language (XML) schema listed on the EPA's ERT Web site. If you claim that some of the performance test information being submitted is confidential business information (CBI), you must submit a complete file generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT Web site, including information claimed to be CBI, on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT or alternate file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph.

(ii) For data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT Web site at the time of the test, you must submit the results of the performance test to the Administrator at the appropriate address listed in § 63.13.

(2) Within 60 days after the date of completing each CEMS performance evaluation (as defined in 63.2), you must submit the results of the performance evaluation following the procedure specified in either paragraph (h)(2)(i) or (ii) of this section.

(i) For performance evaluations of continuous monitoring systems measuring relative accuracy test audit (RATA) pollutants that are supported by the EPA's ERT as listed on the EPA's ERT Web site at the time of the evaluation, you must submit the results of the performance evaluation to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX.) Performance evaluation data must be submitted in a file format generated through the use of the EPA's ERT or an alternate file format consistent with the XML schema listed on the EPA's ERT Web site. If you claim that some of the performance evaluation information being transmitted is CBI, you must submit a complete file generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT Web site, including information claimed to be CBI, on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT or alternate file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph.

(ii) For any performance evaluations of continuous monitoring systems measuring RATA pollutants that are not supported by the EPA's ERT as listed on the ERT Web site at the time of the evaluation, you must submit the results of the performance evaluation to the Administrator at the appropriate address listed in § 63.13.

(3) You must submit all reports required by Table 9 of this subpart electronically to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX.) You must use the appropriate electronic report in CEDRI for this subpart. Instead of using the electronic report in CEDRI for this subpart, you may submit an alternate electronic file consistent with the XML schema listed on the CEDRI Web site (<http://www.epa.gov/ttn/chief/cedri/index.html>), once the XML schema is available. If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, you must submit the report to the Administrator at the appropriate address listed in § 63.13. You must begin submitting reports via CEDRI no later than 90 days after the form becomes available in CEDRI.

[78 FR 7183, Jan. 31, 2013, as amended at 80 FR 72814, Nov. 20, 2015]

### **§ 63.7555 What records must I keep?**

(a) You must keep records according to paragraphs (a)(1) and (2) of this section.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that you submitted, according to the requirements in § 63.10(b)(2)(xiv).

(2) Records of performance tests, fuel analyses, or other compliance demonstrations and performance evaluations as required in § 63.10(b)(2)(viii).

(3) For units in the limited use subcategory, you must keep a copy of the federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent and fuel use records for the days the boiler or process heater was operating.

(b) For each CEMS, COMS, and continuous monitoring system you must keep records according to paragraphs (b)(1) through (5) of this section.

(1) Records described in § 63.10(b)(2)(vii) through (xi).

(2) Monitoring data for continuous opacity monitoring system during a performance evaluation as required in § 63.6(h)(7)(i) and (ii).

(3) Previous (*i.e.*, superseded) versions of the performance evaluation plan as required in § 63.8(d)(3).

(4) Request for alternatives to relative accuracy test for CEMS as required in § 63.8(f)(6)(i).

(5) Records of the date and time that each deviation started and stopped.

(c) You must keep the records required in Table 8 to this subpart including records of all monitoring data and calculated averages for applicable operating limits, such as opacity, pressure drop, pH, and operating load, to show continuous compliance with each emission limit and operating limit that applies to you.

(d) For each boiler or process heater subject to an emission limit in Table 1 or 2 or Tables 11 through 15 to this subpart, you must also keep the applicable records in paragraphs (d)(1) through (11) of this section.

(1) You must keep records of monthly fuel use by each boiler or process heater, including the type(s) of fuel and amount(s) used.

(2) If you combust non-hazardous secondary materials that have been determined not to be solid waste pursuant to § 241.3(b)(1) and (2) of this chapter, you must keep a record that documents how the secondary material meets each of the legitimacy criteria under § 241.3(d)(1) of this chapter. If you combust a fuel that has been processed from a discarded non-hazardous secondary material pursuant to § 241.3(b)(4) of this chapter, you must keep records as to how the operations that produced the fuel satisfy the definition of processing in § 241.2 of this chapter. If the fuel received a non-waste determination pursuant to the petition process submitted under § 241.3(c) of this chapter, you must keep a record that documents how the fuel satisfies the requirements of the petition process. For operating units that combust non-hazardous secondary materials as fuel per § 241.4 of this chapter, you must keep records documenting that the material is listed as a non-waste under § 241.4(a) of this chapter. Units exempt from the incinerator standards under section 129(g)(1) of the Clean Air Act because they are qualifying facilities burning a homogeneous waste stream do not need to maintain the records described in this paragraph (d)(2).

(3) A copy of all calculations and supporting documentation of maximum chlorine fuel input, using Equation 7 of § 63.7530, that were done to demonstrate continuous compliance with the HCl emission limit, for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of HCl emission rates, using Equation 16 of § 63.7530, that were done to demonstrate compliance with the HCl emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum chlorine fuel input or HCl emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate chlorine fuel input, or HCl emission rate, for each boiler and process heater.

(4) A copy of all calculations and supporting documentation of maximum mercury fuel input, using Equation 8 of § 63.7530, that were done to demonstrate continuous compliance with the mercury emission limit for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of mercury emission rates, using Equation 17 of § 63.7530, that were done to demonstrate compliance with the mercury emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum mercury fuel input or mercury emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate mercury fuel input, or mercury emission rates, for each boiler and process heater.

(5) If, consistent with § 63.7515(b), you choose to stack test less frequently than annually, you must keep a record that documents that your emissions in the previous stack test(s) were less than 75 percent of the applicable emission limit (or, in specific instances noted in Tables 1 and 2 or 11 through 15 to this subpart, less than the applicable emission limit), and document that there was no change in source operations including fuel composition and operation of air pollution control equipment that would cause emissions of the relevant pollutant to increase within the past year.

(6) Records of the occurrence and duration of each malfunction of the boiler or process heater, or of the associated air pollution control and monitoring equipment.

(7) Records of actions taken during periods of malfunction to minimize emissions in accordance with the general duty to minimize emissions in § 63.7500(a)(3), including corrective actions to restore the malfunctioning boiler or process heater, air pollution control, or monitoring equipment to its normal or usual manner of operation.

(8) A copy of all calculations and supporting documentation of maximum TSM fuel input, using Equation 9 of § 63.7530, that were done to demonstrate continuous compliance with the TSM emission limit for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of TSM emission rates, using Equation 18 of § 63.7530, that were done to demonstrate compliance with the TSM emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum TSM fuel input or TSM emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate TSM fuel input, or TSM emission rates, for each boiler and process heater.

(9) You must maintain records of the calendar date, time, occurrence and duration of each startup and shutdown.

(10) You must maintain records of the type(s) and amount(s) of fuels used during each startup and shutdown.

(11) For each startup period, for units selecting paragraph (2) of the definition of "startup" in § 63.7575 you must maintain records of the time that clean fuel combustion begins; the time when you start feeding fuels that are not clean fuels; the time when useful thermal energy is first supplied; and the time when the PM controls are engaged.

(12) If you choose to rely on paragraph (2) of the definition of "startup" in § 63.7575, for each startup period, you must maintain records of the hourly steam temperature, hourly steam pressure, hourly steam flow, hourly flue gas temperature, and all hourly average CMS data (e.g., CEMS, PM CPMS, COMS, ESP total secondary electric power input, scrubber pressure drop, scrubber liquid flow rate) collected during each startup period to confirm that the control devices are engaged. In addition, if compliance with the PM emission limit is demonstrated using a PM control device, you must maintain records as specified in paragraphs (d)(12)(i) through (iii) of this section.

(i) For a boiler or process heater with an electrostatic precipitator, record the number of fields in service, as well as each field's secondary voltage and secondary current during each hour of startup.

(ii) For a boiler or process heater with a fabric filter, record the number of compartments in service, as well as the differential pressure across the baghouse during each hour of startup.

(iii) For a boiler or process heater with a wet scrubber needed for filterable PM control, record the scrubber's liquid flow rate and the pressure drop during each hour of startup.

(13) If you choose to use paragraph (2) of the definition of "startup" in § 63.7575 and you find that you are unable to safely engage and operate your PM control(s) within 1 hour of first firing of non-clean fuels, you may choose to rely on paragraph (1) of definition of "startup" in § 63.7575 or you may submit to the delegated permitting authority a request for a variance with the PM controls requirement, as described below.

(i) The request shall provide evidence of a documented manufacturer-identified safety issue.

(ii) The request shall provide information to document that the PM control device is adequately designed and sized to meet the applicable PM emission limit.

(iii) In addition, the request shall contain documentation that:

(A) The unit is using clean fuels to the maximum extent possible to bring the unit and PM control device up to the temperature necessary to alleviate or prevent the identified safety issues prior to the combustion of primary fuel;

(B) The unit has explicitly followed the manufacturer's procedures to alleviate or prevent the identified safety issue; and



(C) Identifies with specificity the details of the manufacturer's statement of concern.

(iv) You must comply with all other work practice requirements, including but not limited to data collection, recordkeeping, and reporting requirements.

(e) If you elect to average emissions consistent with § 63.7522, you must additionally keep a copy of the emission averaging implementation plan required in § 63.7522(g), all calculations required under § 63.7522, including monthly records of heat input or steam generation, as applicable, and monitoring records consistent with § 63.7541.

(f) If you elect to use efficiency credits from energy conservation measures to demonstrate compliance according to § 63.7533, you must keep a copy of the Implementation Plan required in § 63.7533(d) and copies of all data and calculations used to establish credits according to § 63.7533(b), (c), and (f).

(g) If you elected to demonstrate that the unit meets the specification for mercury for the unit designed to burn gas 1 subcategory, you must maintain monthly records (or at the frequency required by § 63.7540(c)) of the calculations and results of the fuel specification for mercury in Table 6.

(h) If you operate a unit in the unit designed to burn gas 1 subcategory that is subject to this subpart, and you use an alternative fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart under this part, other gas 1 fuel, or gaseous fuel subject to another subpart of this part or part 60, 61, or 65, you must keep records of the total hours per calendar year that alternative fuel is burned and the total hours per calendar year that the unit operated during periods of gas curtailment or gas supply emergencies.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7185, Jan. 31, 2013; 80 FR 72816, Nov. 20, 2015; 87 FR 60846, Oct. 6, 2022]

#### **§ 63.7560 In what form and how long must I keep my records?**

(a) Your records must be in a form suitable and readily available for expeditious review, according to § 63.10(b)(1).

(b) As specified in § 63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record on site, or they must be accessible from on site (for example, through a computer network), for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 63.10(b)(1). You can keep the records off site for the remaining 3 years.

#### **Other Requirements and Information**

#### **§ 63.7565 What parts of the General Provisions apply to me?**

Table 10 to this subpart shows which parts of the General Provisions in §§ 63.1 through 63.15 apply to you.

#### **§ 63.7570 Who implements and enforces this subpart?**

(a) This subpart can be implemented and enforced by the EPA, or an Administrator such as your state, local, or tribal agency. If the EPA Administrator has delegated authority to your state, local, or tribal agency, then that agency (as well as the EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if this subpart is delegated to your state, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a state, local, or tribal agency under 40 CFR part 63, subpart E, the authorities listed in paragraphs (b)(1) through (4) of this section are retained by the EPA Administrator and are not transferred to the state, local, or tribal agency, however, the EPA retains oversight of this subpart and can take enforcement actions, as appropriate.

(1) Approval of alternatives to the emission limits and work practice standards in § 63.7500(a) and (b) under § 63.6(g), except as specified in § 63.7555(d)(13).

(2) Approval of major change to test methods in Table 5 to this subpart under § 63.7(e)(2)(ii) and (f) and as defined in § 63.90, and alternative analytical methods requested under § 63.7521(b)(2).

(3) Approval of major change to monitoring under § 63.8(f) and as defined in § 63.90, and approval of alternative operating parameters under §§ 63.7500(a)(2) and 63.7522(g)(2).

(4) Approval of major change to recordkeeping and reporting under § 63.10(e) and as defined in § 63.90.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7186, Jan. 31, 2013; 80 FR 72817, Nov. 20, 2015]

### § 63.7575 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act, in § 63.2 (the General Provisions), and in this section as follows:

*10-day rolling average* means the arithmetic mean of the previous 240 hours of valid operating data. Valid data excludes hours during startup and shutdown, data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities, and periods when this unit is not operating. The 240 hours should be consecutive, but not necessarily continuous if operations were intermittent.

*12-month rolling average* means the arithmetic mean of the previous 12 months of valid fuel analysis data. The 12 months should be consecutive, but not necessarily continuous if operations were intermittent.

*30-day rolling average* means the arithmetic mean of the previous 720 hours of valid CO CEMS data. The 720 hours should be consecutive, but not necessarily continuous if operations were intermittent. For parameters other than CO, 30-day rolling average means either the arithmetic mean of all valid hours of data from 30 successive operating days or the arithmetic mean of the previous 720 hours of valid operating data. Valid data excludes hours during startup and shutdown, data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities, and periods when this unit is not operating.

*Annual capacity factor* means the ratio between the actual heat input to a boiler or process heater from the fuels burned during a calendar year and the potential heat input to the boiler or process heater had it been operated for 8,760 hours during a year at the maximum steady state design heat input capacity.

*Annual heat input* means the heat input for the 12 months preceding the compliance demonstration.

*Average annual heat input rate* means total heat input divided by the hours of operation for the 12 months preceding the compliance demonstration.

*Bag leak detection system* means a group of instruments that are capable of monitoring particulate matter loadings in the exhaust of a fabric filter (*i.e.*, baghouse) in order to detect bag failures. A bag leak detection system includes, but is not limited to, an instrument that operates on electrodynamic, triboelectric, light scattering, light transmittance, or other principle to monitor relative particulate matter loadings.

*Benchmark* means the fuel heat input for a boiler or process heater for the one-year period before the date that an energy demand reduction occurs, unless it can be demonstrated that a different time period is more representative of historical operations.

*Biodiesel* means a mono-alkyl ester derived from biomass and conforming to ASTM D6751-11b, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels (incorporated by reference, see § 63.14).

*Biomass or bio-based solid fuel* means any biomass-based solid fuel that is not a solid waste. This includes, but is not limited to, wood residue; wood products (e.g., trees, tree stumps, tree limbs, bark, lumber, sawdust, sander dust, chips, scraps, slabs, millings, and shavings); animal manure, including litter and other bedding materials; vegetative agricultural and silvicultural materials, such as logging residues (slash), nut and grain hulls and chaff (e.g., almond, walnut, peanut, rice, and wheat), bagasse, orchard prunings, corn stalks, coffee bean hulls and grounds. This definition of biomass is not intended to suggest that these materials are or are not solid waste.

*Blast furnace gas fuel-fired boiler or process heater* means an industrial/commercial/institutional boiler or process heater that receives 90 percent or more of its total annual gas volume from blast furnace gas.

*Boiler* means an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water. Controlled flame combustion refers to a steady-state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled. A device combusting solid waste, as defined in § 241.3 of this chapter, is not a boiler unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Waste heat boilers are excluded from this definition.

*Boiler system* means the boiler and associated components, such as, the feed water system, the combustion air system, the fuel system (including burners), blowdown system, combustion control systems, steam systems, and condensate return systems.

*Calendar year* means the period between January 1 and December 31, inclusive, for a given year.

*Clean dry biomass* means any biomass-based solid fuel that have not been painted, pigment-stained, or pressure treated, does not contain contaminants at concentrations not normally associated with virgin biomass materials and has a moisture content of less than 20 percent and is not a solid waste.

*Coal* means all solid fuels classifiable as anthracite, bituminous, sub-bituminous, or lignite by ASTM D388 (incorporated by reference, see § 63.14), coal refuse, and petroleum coke. For the purposes of this subpart, this definition of "coal" includes synthetic fuels derived from coal, including but not limited to, solvent-refined coal, coal-oil mixtures, and coal-water mixtures. Coal derived gases are excluded from this definition.

*Coal refuse* means any by-product of coal mining or coal cleaning operations with an ash content greater than 50 percent (by weight) and a heating value less than 13,900 kilojoules per kilogram (6,000 Btu per pound) on a dry basis.

*Commercial/institutional boiler* means a boiler used in commercial establishments or institutional establishments such as medical centers, nursing homes, research centers, institutions of higher education, elementary and secondary schools, libraries, religious establishments, governmental buildings, hotels, restaurants, and laundries to provide electricity, steam, and/or hot water.

*Common stack* means the exhaust of emissions from two or more affected units through a single flue. Affected units with a common stack may each have separate air pollution control systems located before the common stack, or may have a single air pollution control system located after the exhausts come together in a single flue.

*Cost-effective energy conservation measure* means a measure that is implemented to improve the energy efficiency of the boiler or facility that has a payback (return of investment) period of 2 years or less.

*Daily block average* means the arithmetic mean of all valid emission concentrations or parameter levels recorded when a unit is operating measured over the 24-hour period from 12 a.m. (midnight) to 12 a.m. (midnight), except for periods of startup and shutdown or downtime.

*Deviation.*

(1) **Deviation** means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(i) Fails to meet any applicable requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard; or

(ii) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit.

(2) A deviation is not always a violation.

*Dioxins/furans* means tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans.

*Distillate oil* means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see § 63.14) or diesel fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see § 63.14), kerosene, and biodiesel as defined by the American Society of Testing and Materials in ASTM D6751-11b (incorporated by reference, see § 60.14).

*Dry scrubber* means an add-on air pollution control system that injects dry alkaline sorbent (dry injection) or sprays an alkaline sorbent (spray dryer) to react with and neutralize acid gas in the exhaust stream forming a dry powder material. Sorbent injection systems used as control devices in fluidized bed boilers and process heaters are included in this definition. A dry scrubber is a dry control system.

*Dutch oven* means a unit having a refractory-walled cell connected to a conventional boiler setting. Fuel materials are introduced through an opening in the roof of the dutch oven and burn in a pile on its floor. Fluidized bed boilers are not part of the dutch oven design category.

*Efficiency credit* means emission reductions above those required by this subpart. Efficiency credits generated may be used to comply with the emissions limits. Credits may come from pollution prevention projects that result in reduced fuel use by affected units. Boilers that are shut down cannot be used to generate credits unless the facility provides documentation linking the permanent shutdown to implementation of the energy conservation measures identified in the energy assessment.

*Electric utility steam generating unit (EGU)* means a fossil fuel-fired combustion unit of more than 25 megawatts electric (MWe) that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is considered an electric utility steam generating unit. To be "capable of combusting" fossil fuels, an EGU would need to have these fuels allowed in their operating permits and have the appropriate fuel handling facilities on-site or otherwise available (e.g., coal handling equipment, including coal storage area, belts and conveyers, pulverizers, etc.; oil storage facilities). In addition, fossil fuel-fired EGU means any EGU that fired fossil fuel for more than 10.0 percent of the average annual heat input in any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year after April 16, 2012.

*Electrostatic precipitator (ESP)* means an add-on air pollution control device used to capture particulate matter by charging the particles using an electrostatic field, collecting the particles using a grounded collecting surface, and transporting the particles into a hopper. An electrostatic precipitator is usually a dry control system.

*Energy assessment* means the following for the emission units covered by this subpart:

(1) The energy assessment for facilities with affected boilers and process heaters with a combined heat input capacity of less than 0.3 trillion Btu (Tbtu) per year will be 8 on-site technical labor hours in length maximum, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s), process heater(s), and any on-site energy use system(s) accounting for at least 50 percent of the affected boiler(s) energy (e.g., steam, hot water, process heat, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities, within the limit of performing an 8-hour on-site energy assessment.

(2) The energy assessment for facilities with affected boilers and process heaters with a combined heat input capacity of 0.3 to 1.0 TBtu/year will be 24 on-site technical labor hours in length maximum, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s), process heater(s), and any on-site energy use system(s) accounting for at least 33 percent of the energy (e.g., steam, hot water, process heat, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities, within the limit of performing a 24-hour on-site energy assessment.

(3) The energy assessment for facilities with affected boilers and process heaters with a combined heat input capacity greater than 1.0 TBtu/year will be up to 24 on-site technical labor hours in length for the first TBtu/yr plus 8 on-site technical labor hours for every additional 1.0 TBtu/yr not to exceed 160 on-site technical hours, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s), process heater(s), and any on-site energy use system(s) accounting for at least 20 percent of the energy (e.g., steam, process heat, hot water, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities.

(4) The on-site energy use systems serving as the basis for the percent of affected boiler(s) and process heater(s) energy production in paragraphs (1), (2), and (3) of this definition may be segmented by production area or energy use area as most logical and applicable to the specific facility being assessed (e.g., product X manufacturing area; product Y drying area; Building Z).

*Energy management practices* means the set of practices and procedures designed to manage energy use that are demonstrated by the facility's energy policies, a facility energy manager and other staffing responsibilities, energy performance measurement and tracking methods, an energy saving goal, action plans, operating procedures, internal reporting requirements, and periodic review intervals used at the facility.

*Energy management program* means a program that includes a set of practices and procedures designed to manage energy use that are demonstrated by the facility's energy policies, a facility energy manager and other staffing responsibilities, energy performance measurement and tracking methods, an energy saving goal, action plans, operating procedures, internal reporting requirements, and periodic review intervals used at the facility. Facilities may establish their program through energy management systems compatible with ISO 50001.

*Energy use system* includes the following systems located on-site that use energy (steam, hot water, or electricity) provided by the affected boiler or process heater: process heating; compressed air systems; machine drive (motors, pumps, fans); process cooling; facility heating, ventilation, and air-conditioning systems; hot water systems; building envelop; and lighting; or other systems that use steam, hot water, process heat, or electricity provided by the affected boiler or process heater. Energy use systems are only those systems using energy clearly produced by affected boilers and process heaters.

*Equivalent* means the following only as this term is used in Table 6 to this subpart:

(1) An equivalent sample collection procedure means a published voluntary consensus standard or practice (VCS) or EPA method that includes collection of a minimum of three composite fuel samples, with each composite consisting of a minimum of three increments collected at approximately equal intervals over the test period.

(2) An equivalent sample compositing procedure means a published VCS or EPA method to systematically mix and obtain a representative subsample (part) of the composite sample.

(3) An equivalent sample preparation procedure means a published VCS or EPA method that: Clearly states that the standard, practice or method is appropriate for the pollutant and the fuel matrix; or is cited as an appropriate sample preparation standard, practice or method for the pollutant in the chosen VCS or EPA determinative or analytical method.

(4) An equivalent procedure for determining heat content means a published VCS or EPA method to obtain gross calorific (or higher heating) value.

(5) An equivalent procedure for determining fuel moisture content means a published VCS or EPA method to obtain moisture content. If the sample analysis plan calls for determining metals (especially the mercury,

selenium, or arsenic) using an aliquot of the dried sample, then the drying temperature must be modified to prevent vaporizing these metals. On the other hand, if metals analysis is done on an "as received" basis, a separate aliquot can be dried to determine moisture content and the metals concentration mathematically adjusted to a dry basis.

(6) An equivalent pollutant (mercury, HCl) determinative or analytical procedure means a published VCS or EPA method that clearly states that the standard, practice, or method is appropriate for the pollutant and the fuel matrix and has a published detection limit equal or lower than the methods listed in Table 6 to this subpart for the same purpose.

*Fabric filter* means an add-on air pollution control device used to capture particulate matter by filtering gas streams through filter media, also known as a baghouse. A fabric filter is a dry control system.

*Federally enforceable* means all limitations and conditions that are enforceable by the EPA Administrator, including, but not limited to, the requirements of 40 CFR parts 60, 61, 63, and 65, requirements within any applicable state implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 40 CFR 51.24.

*Fluidized bed boiler* means a boiler utilizing a fluidized bed combustion process that is not a pulverized coal boiler.

*Fluidized bed boiler with an integrated fluidized bed heat exchanger* means a boiler utilizing a fluidized bed combustion where the entire tube surface area is located outside of the furnace section at the exit of the cyclone section and exposed to the flue gas stream for conductive heat transfer. This design applies only to boilers in the unit designed to burn coal/solid fossil fuel subcategory that fire coal refuse.

*Fluidized bed combustion* means a process where a fuel is burned in a bed of granulated particles, which are maintained in a mobile suspension by the forward flow of air and combustion products.

*Fossil fuel* means natural gas, oil, coal, and any form of solid, liquid, or gaseous fuel derived from such material.

*Fuel cell* means a boiler type in which the fuel is dropped onto suspended fixed grates and is fired in a pile. The refractory-lined fuel cell uses combustion air preheating and positioning of secondary and tertiary air injection ports to improve boiler efficiency. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, and suspension burners are not part of the fuel cell subcategory.

*Fuel type* means each category of fuels that share a common name or classification. Examples include, but are not limited to, bituminous coal, sub-bituminous coal, lignite, anthracite, biomass, distillate oil, residual oil. Individual fuel types received from different suppliers are not considered new fuel types.

*Gaseous fuel* includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, refinery gas, and biogas. Blast furnace gas and process gases that are regulated under another subpart of this part, or part 60, part 61, or part 65 of this chapter, are exempted from this definition.

*Heat input* means heat derived from combustion of fuel in a boiler or process heater and does not include the heat input from preheated combustion air, recirculated flue gases, returned condensate, or exhaust gases from other sources such as gas turbines, internal combustion engines, kilns, etc.

*Heavy liquid* includes residual oil and any other liquid fuel not classified as a light liquid.

*Hourly average* means the arithmetic average of at least four CMS data values representing the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CMS calibration, quality assurance, or maintenance activities are being performed.

*Hot water heater* means a closed vessel with a capacity of no more than 120 U.S. gallons in which water is heated by combustion of gaseous, liquid, or biomass/bio-based solid fuel and is withdrawn for use external to the vessel. Hot water boilers (i.e., not generating steam) combusting gaseous, liquid, or biomass fuel with a heat input capacity of less than 1.6 million Btu per hour are included in this definition. The 120 U.S. gallon capacity threshold to be

considered a hot water heater is independent of the 1.6 MMBtu/hr heat input capacity threshold for hot water boilers. Hot water heater also means a tankless unit that provides on demand hot water.

*Hybrid suspension grate boiler* means a boiler designed with air distributors to spread the fuel material over the entire width and depth of the boiler combustion zone. The biomass fuel combusted in these units exceeds a moisture content of 40 percent on an as-fired annual heat input basis as demonstrated by monthly fuel analysis. The drying and much of the combustion of the fuel takes place in suspension, and the combustion is completed on the grate or floor of the boiler. Fluidized bed, dutch oven, and pile burner designs are not part of the hybrid suspension grate boiler design category.

*Industrial boiler* means a boiler used in manufacturing, processing, mining, and refining or any other industry to provide steam, hot water, and/or electricity.

*Light liquid* includes distillate oil, biodiesel, or vegetable oil.

*Limited-use boiler or process heater* means any boiler or process heater that burns any amount of solid, liquid, or gaseous fuels and has a federally enforceable annual capacity factor of no more than 10 percent.

*Liquid fuel* includes, but is not limited to, light liquid, heavy liquid, any form of liquid fuel derived from petroleum, used oil, liquid biofuels, biodiesel, and vegetable oil.

*Load fraction* means the actual heat input of a boiler or process heater divided by heat input during the performance test that established the minimum sorbent injection rate or minimum activated carbon injection rate, expressed as a fraction (e.g., for 50 percent load the load fraction is 0.5). For boilers and process heaters that co-fire natural gas or refinery gas with a solid or liquid fuel, the load fraction is determined by the actual heat input of the solid or liquid fuel divided by heat input of the solid or liquid fuel fired during the performance test (e.g., if the performance test was conducted at 100 percent solid fuel firing, for 100 percent load firing 50 percent solid fuel and 50 percent natural gas the load fraction is 0.5).

*Major source for oil and natural gas production facilities*, as used in this subpart, shall have the same meaning as in § 63.2, except that:

- (1) Emissions from any oil or gas exploration or production well (with its associated equipment, as defined in this section), and emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units to determine whether such emission points or stations are major sources, even when emission points are in a contiguous area or under common control;
- (2) Emissions from processes, operations, or equipment that are not part of the same facility, as defined in this section, shall not be aggregated; and
- (3) For facilities that are production field facilities, only HAP emissions from glycol dehydration units and storage vessels with the potential for flash emissions shall be aggregated for a major source determination. For facilities that are not production field facilities, HAP emissions from all HAP emission units shall be aggregated for a major source determination.

*Metal process furnaces* are a subcategory of process heaters, as defined in this subpart, which include natural gas-fired annealing furnaces, preheat furnaces, reheat furnaces, aging furnaces, heat treat furnaces, and homogenizing furnaces.

*Million Btu (MMBtu)* means one million British thermal units.

*Minimum activated carbon injection rate* means load fraction multiplied by the lowest hourly average activated carbon injection rate measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

*Minimum oxygen level* means the lowest hourly average oxygen level measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

*Minimum pressure drop* means the lowest hourly average pressure drop measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

*Minimum scrubber effluent pH* means the lowest hourly average sorbent liquid pH measured at the inlet to the wet scrubber according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable hydrogen chloride emission limit.

*Minimum scrubber liquid flow rate* means the lowest hourly average liquid flow rate (e.g., to the PM scrubber or to the acid gas scrubber) measured according to Table 7 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limit.

*Minimum scrubber pressure drop* means the lowest hourly average scrubber pressure drop measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

*Minimum sorbent injection rate* means:

- (1) The load fraction multiplied by the lowest hourly average sorbent injection rate for each sorbent measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits; or
- (2) For fluidized bed combustion not using an acid gas wet scrubber or dry sorbent injection control technology to comply with the HCl emission limit, the lowest average ratio of sorbent to sulfur measured during the most recent performance test.

*Minimum total secondary electric power* means the lowest hourly average total secondary electric power determined from the values of secondary voltage and secondary current to the electrostatic precipitator measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits.

*Natural gas* means:

- (1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or
- (2) Liquefied petroleum gas, as defined in ASTM D1835 (incorporated by reference, see § 63.14); or
- (3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot); or
- (4) Propane or propane derived synthetic natural gas. Propane means a colorless gas derived from petroleum and natural gas, with the molecular structure  $C_3H_8$ .

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

*Operating day* means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the boiler or process heater unit. It is not necessary for fuel to be combusted for the entire 24-hour period. For calculating rolling average emissions, an operating day does not include the hours of operation during startup or shutdown.

*Other combustor* means a unit designed to burn solid fuel that is not classified as a dutch oven, fluidized bed, fuel cell, hybrid suspension grate boiler, pulverized coal boiler, stoker, sloped grate, or suspension boiler as defined in this subpart.



*Other gas 1 fuel* means a gaseous fuel that is not natural gas or refinery gas and does not exceed a maximum mercury concentration of 40 micrograms/cubic meters of gas.

*Oxygen analyzer system* means all equipment required to determine the oxygen content of a gas stream and used to monitor oxygen in the boiler or process heater flue gas, boiler or process heater, firebox, or other appropriate location. This definition includes oxygen trim systems. The source owner or operator must install, calibrate, maintain, and operate the oxygen analyzer system in accordance with the manufacturer's recommendations.

*Oxygen trim system* means a system of monitors that is used to maintain excess air at the desired level in a combustion device over its operating load range. A typical system consists of a flue gas oxygen and/or CO monitor that automatically provides a feedback signal to the combustion air controller or draft controller.

*Particulate matter (PM)* means any finely divided solid or liquid material, other than uncombined water, as measured by the test methods specified under this subpart, or an approved alternative method.

*Period of gas curtailment or supply interruption* means a period of time during which the supply of gaseous fuel to an affected boiler or process heater is restricted or halted for reasons beyond the control of the facility. The act of entering into a contractual agreement with a supplier of natural gas established for curtailment purposes does not constitute a reason that is under the control of a facility for the purposes of this definition. An increase in the cost or unit price of natural gas due to normal market fluctuations not during periods of supplier delivery restriction does not constitute a period of natural gas curtailment or supply interruption. On-site gaseous fuel system emergencies or equipment failures qualify as periods of supply interruption when the emergency or failure is beyond the control of the facility.

*Pile burner* means a boiler design incorporating a design where the anticipated biomass fuel has a high relative moisture content. Grates serve to support the fuel, and underfire air flowing up through the grates provides oxygen for combustion, cools the grates, promotes turbulence in the fuel bed, and fires the fuel. The most common form of pile burning is the dutch oven.

*Process heater* means an enclosed device using controlled flame, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material (e.g., glycol or a mixture of glycol and water) for use in a process unit, instead of generating steam. Process heaters are devices in which the combustion gases do not come into direct contact with process materials. A device combusting solid waste, as defined in § 241.3 of this chapter, is not a process heater unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Process heaters do not include units used for comfort heat or space heat, food preparation for on-site consumption, or autoclaves. Waste heat process heaters are excluded from this definition.

*Pulverized coal boiler* means a boiler in which pulverized coal or other solid fossil fuel is introduced into an air stream that carries the coal to the combustion chamber of the boiler where it is fired in suspension.

*Qualified energy assessor* means:

(1) Someone who has demonstrated capabilities to evaluate energy savings opportunities for steam generation and major energy using systems, including, but not limited to:

- (i) Boiler combustion management.
- (ii) Boiler thermal energy recovery, including
  - (A) Conventional feed water economizer,
  - (B) Conventional combustion air preheater, and
  - (C) Condensing economizer.
- (iii) Boiler blowdown thermal energy recovery.

- (iv) Primary energy resource selection, including
    - (A) Fuel (primary energy source) switching, and
    - (B) Applied steam energy versus direct-fired energy versus electricity.
  - (v) Insulation issues.
  - (vi) Steam trap and steam leak management.
  - (vi) Condensate recovery.
  - (viii) Steam end-use management.
- (2) Capabilities and knowledge includes, but is not limited to:
- (i) Background, experience, and recognized abilities to perform the assessment activities, data analysis, and report preparation.
  - (ii) Familiarity with operating and maintenance practices for steam or process heating systems.
  - (iii) Additional potential steam system improvement opportunities including improving steam turbine operations and reducing steam demand.
  - (iv) Additional process heating system opportunities including effective utilization of waste heat and use of proper process heating methods.
  - (v) Boiler-steam turbine cogeneration systems.
  - (vi) Industry specific steam end-use systems.

*Refinery gas* means any gas that is generated at a petroleum refinery and is combusted. Refinery gas includes natural gas when the natural gas is combined and combusted in any proportion with a gas generated at a refinery. Refinery gas includes gases generated from other facilities when that gas is combined and combusted in any proportion with gas generated at a refinery.

*Regulated gas stream* means an offgas stream that is routed to a boiler or process heater for the purpose of achieving compliance with a standard under another subpart of this part or part 60, part 61, or part 65 of this chapter.

*Residential boiler* means a boiler used to provide heat and/or hot water and/or as part of a residential combined heat and power system. This definition includes boilers located at an institutional facility (e.g., university campus, military base, church grounds) or commercial/industrial facility (e.g., farm) used primarily to provide heat and/or hot water for:

- (1) A dwelling containing four or fewer families; or
- (2) A single unit residence dwelling that has since been converted or subdivided into condominiums or apartments.

*Residual oil* means crude oil, fuel oil that does not comply with the specifications under the definition of distillate oil, and all fuel oil numbers 4, 5, and 6, as defined by the American Society of Testing and Materials in ASTM D396-10 (incorporated by reference, see § 63.14(b)).

*Responsible official* means responsible official as defined in § 70.2.

*Rolling average* means the average of all data collected during the applicable averaging period. For demonstration of compliance with a CO CEMS-based emission limit based on CO concentration a 30-day (10-day) rolling average is comprised of the average of all the hourly average concentrations over the previous 720 (240) operating hours calculated each operating day. To demonstrate compliance on a 30-day rolling average basis for parameters other than CO, you must indicate the basis of the 30-day rolling average period you are using for compliance, as discussed in § 63.7545(e)(2)(iii). If you indicate the 30 operating day basis, you must calculate a new average value each operating day and shall include the measured hourly values for the preceding 30 operating days. If you select the 720 operating hours basis, you must average of all the hourly average concentrations over the previous 720 operating hours calculated each operating day.

*Secondary material* means the material as defined in § 241.2 of this chapter.

*Shutdown* means the period in which cessation of operation of a boiler or process heater is initiated for any purpose. Shutdown begins when the boiler or process heater no longer supplies useful thermal energy (such as heat or steam) for heating, cooling, or process purposes and/or generates electricity or when no fuel is being fed to the boiler or process heater, whichever is earlier. Shutdown ends when the boiler or process heater no longer supplies useful thermal energy (such as steam or heat) for heating, cooling, or process purposes and/or generates electricity, and no fuel is being combusted in the boiler or process heater.

*Sloped grate* means a unit where the solid fuel is fed to the top of the grate from where it slides downwards; while sliding the fuel first dries and then ignites and burns. The ash is deposited at the bottom of the grate. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, suspension burners, and fuel cells are not considered to be a sloped grate design.

*Solid fossil fuel* includes, but is not limited to, coal, coke, petroleum coke, and tire derived fuel.

*Solid fuel* means any solid fossil fuel or biomass or bio-based solid fuel.

*Startup* means:

- (1) Either the first-ever firing of fuel in a boiler or process heater for the purpose of supplying useful thermal energy for heating and/or producing electricity, or for any other purpose, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the useful thermal energy from the boiler or process heater is supplied for heating, and/or producing electricity, or for any other purpose, or
- (2) The period in which operation of a boiler or process heater is initiated for any purpose. Startup begins with either the first-ever firing of fuel in a boiler or process heater for the purpose of supplying useful thermal energy (such as steam or heat) for heating, cooling or process purposes, or producing electricity, or the firing of fuel in a boiler or process heater for any purpose after a shutdown event. Startup ends four hours after when the boiler or process heater supplies useful thermal energy (such as heat or steam) for heating, cooling, or process purposes, or generates electricity, whichever is earlier.

*Steam output* means:

- (1) For a boiler that produces steam for process or heating only (no power generation), the energy content in terms of MMBtu of the boiler steam output,
- (2) For a boiler that cogenerates process steam and electricity (also known as combined heat and power), the total energy output, which is the sum of the energy content of the steam exiting the turbine and sent to process in MMBtu and the energy of the electricity generated converted to MMBtu at a rate of 10,000 Btu per kilowatt-hour generated (10 MMBtu per megawatt-hour), and
- (3) For a boiler that generates only electricity, the alternate output-based emission limits would be the appropriate emission limit from Table 1, 2, 14, or 15 to this subpart in units of pounds per million Btu heat input (lb per MWh).
- (4) For a boiler that performs multiple functions and produces steam to be used for any combination of paragraphs (1), (2), and (3) of this definition that includes electricity generation of paragraph (3) of this definition,

the total energy output, in terms of MMBtu of steam output, is the sum of the energy content of steam sent directly to the process and/or used for heating ( $S_1$ ), the energy content of turbine steam sent to process plus energy in electricity according to paragraph (2) of this definition ( $S_2$ ), and the energy content of electricity generated by a electricity only turbine as paragraph (3) of this definition ( $MW_{(3)}$ ) and would be calculated using Equation 1 to this definition. In the case of boilers supplying steam to one or more common headers,  $S_1$ ,  $S_2$ , and  $MW_{(3)}$  for each boiler would be calculated based on its (steam energy) contribution (fraction of total steam energy) to the common header.

## Equation 1 to the definition *Steam Output*

$$SO_M = S_1 + S_2 + (MW_{(3)} \times CFn) \quad (\text{Eq. 1})$$

Where:

$SO_M$  = Total steam output for multi-function boiler, MMBtu.

$S_1$  = Energy content of steam sent directly to the process and/or used for heating, MMBtu.

$S_2$  = Energy content of turbine steam sent to the process plus energy in electricity according to paragraph (2) of this definition, MMBtu.

$MW_{(3)}$  = Electricity generated according to paragraph (3) of this definition, MWh.

$CFn$  = Conversion factor for the appropriate subcategory for converting electricity generated according to paragraph (3) of this definition to equivalent steam energy, MMBtu/MWh.

$CFn$  for emission limits for boilers in the unit designed to burn solid fuel subcategory = 10.8.

$CFn$  PM and CO emission limits for boilers in one of the subcategories of units designed to burn coal = 11.7.

$CFn$  PM and CO emission limits for boilers in one of the subcategories of units designed to burn biomass = 12.1.

$CFn$  for emission limits for boilers in one of the subcategories of units designed to burn liquid fuel = 11.2.

$CFn$  for emission limits for boilers in the unit designed to burn gas 2 (other) subcategory = 6.2.

*Stoker* means a unit consisting of a mechanically operated fuel feeding mechanism, a stationary or moving grate to support the burning of fuel and admit under-grate air to the fuel, an overfire air system to complete combustion, and an ash discharge system. This definition of stoker includes air swept stokers. There are two general types of stokers: Underfeed and overfeed. Overfeed stokers include mass feed and spreader stokers. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, suspension burners, and fuel cells are not considered to be a stoker design.

*Stoker/sloped grate/other unit designed to burn kiln dried biomass* means the unit is in the units designed to burn biomass/bio-based solid subcategory that is either a stoker, sloped grate, or other combustor design and is not in the stoker/sloped grate/other units designed to burn wet biomass subcategory.

*Stoker/sloped grate/other unit designed to burn wet biomass* means the unit is in the units designed to burn biomass/bio-based solid subcategory that is either a stoker, sloped grate, or other combustor design and any of the biomass/bio-based solid fuel combusted in the unit exceeds 20 percent moisture on an annual heat input basis.

*Suspension burner* means a unit designed to fire dry biomass/biobased solid particles in suspension that are conveyed in an airstream to the furnace like pulverized coal. The combustion of the fuel material is completed on a grate or floor below. The biomass/biobased fuel combusted in the unit shall not exceed 20 percent moisture on an

annual heat input basis. Fluidized bed, dutch oven, pile burner, and hybrid suspension grate units are not part of the suspension burner subcategory.

*Temporary boiler* means any gaseous or liquid fuel boiler or process heater that is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A boiler or process heater is not a temporary boiler or process heater if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

(2) The boiler or process heater or a replacement remains at a location within the facility and performs the same or similar function for more than 12 consecutive months, unless the regulatory agency approves an extension. An extension may be granted by the regulating agency upon petition by the owner or operator of a unit specifying the basis for such a request. Any temporary boiler or process heater that replaces a temporary boiler or process heater at a location and performs the same or similar function will be included in calculating the consecutive time period.

(3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year.

(4) The equipment is moved from one location to another within the facility but continues to perform the same or similar function and serve the same electricity, process heat, steam, and/or hot water system in an attempt to circumvent the residence time requirements of this definition.

*Total selected metals (TSM)* means the sum of the following metallic hazardous air pollutants: arsenic, beryllium, cadmium, chromium, lead, manganese, nickel and selenium.

*Traditional fuel* means the fuel as defined in § 241.2 of this chapter.

*Tune-up* means adjustments made to a boiler or process heater in accordance with the procedures outlined in § 63.7540(a)(10).

*Ultra low sulfur liquid fuel* means a distillate oil that has less than or equal to 15 ppm sulfur.

*Unit designed to burn biomass/bio-based solid subcategory* includes any boiler or process heater that burns at least 10 percent biomass or bio-based solids on an annual heat input basis in combination with solid fossil fuels, liquid fuels, or gaseous fuels.

*Unit designed to burn coal/solid fossil fuel subcategory* includes any boiler or process heater that burns any coal or other solid fossil fuel alone or at least 10 percent coal or other solid fossil fuel on an annual heat input basis in combination with liquid fuels, gaseous fuels, or less than 10 percent biomass and bio-based solids on an annual heat input basis.

*Unit designed to burn gas 1 subcategory* includes any boiler or process heater that burns only natural gas, refinery gas, and/or other gas 1 fuels. Gaseous fuel boilers and process heaters that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year, are included in this definition. Gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply interruptions of any duration are also included in this definition.

*Unit designed to burn gas 2 (other) subcategory* includes any boiler or process heater that is not in the unit designed to burn gas 1 subcategory and burns any gaseous fuels either alone or in combination with less than 10 percent coal/solid fossil fuel, and less than 10 percent biomass/bio-based solid fuel on an annual heat input basis, and no liquid fuels. Gaseous fuel boilers and process heaters that are not in the unit designed to burn gas 1 subcategory and that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year, are included in this definition. Gaseous fuel boilers and process heaters that are not in the unit designed to burn gas 1 subcategory and that burn liquid fuel during periods of gas curtailment or gas supply interruption of any duration are also included in this definition.

*Unit designed to burn heavy liquid subcategory* means a unit in the unit designed to burn liquid subcategory where at least 10 percent of the heat input from liquid fuels on an annual heat input basis comes from heavy liquids.

*Unit designed to burn light liquid subcategory* means a unit in the unit designed to burn liquid subcategory that is not part of the unit designed to burn heavy liquid subcategory.

*Unit designed to burn liquid subcategory* includes any boiler or process heater that burns any liquid fuel, but less than 10 percent coal/solid fossil fuel and less than 10 percent biomass/bio-based solid fuel on an annual heat input basis, either alone or in combination with gaseous fuels. Units in the unit design to burn gas 1 or unit designed to burn gas 2 (other) subcategories that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year are not included in this definition. Units in the unit design to burn gas 1 or unit designed to burn gas 2 (other) subcategories during periods of gas curtailment or gas supply interruption of any duration are also not included in this definition.

*Unit designed to burn liquid fuel that is a non-continental unit* means an industrial, commercial, or institutional boiler or process heater meeting the definition of the unit designed to burn liquid subcategory located in the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

*Unit designed to burn solid fuel subcategory* means any boiler or process heater that burns only solid fuels or at least 10 percent solid fuel on an annual heat input basis in combination with liquid fuels or gaseous fuels.

*Useful thermal energy* means energy (*i.e.*, steam, hot water, or process heat) that meets the minimum operating temperature, flow, and/or pressure required by any energy use system that uses energy provided by the affected boiler or process heater.

*Vegetable oil* means oils extracted from vegetation.

*Voluntary Consensus Standards or VCS* mean technical standards (*e.g.*, materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. EPA/Office of Air Quality Planning and Standards, by precedent, has only used VCS that are written in English. Examples of VCS bodies are: American Society of Testing and Materials (ASTM 100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428-B2959, (800) 262-1373, <http://www.astm.org>), American Society of Mechanical Engineers (ASME ASME, Three Park Avenue, New York, NY 10016-5990, (800) 843-2763, <http://www.asme.org>), International Standards Organization (ISO 1, ch. de la Voie-Creuse, Case postale 56, CH-1211 Geneva 20, Switzerland, + 41 22 749 01 11, <http://www.iso.org/iso/home.htm>), Standards Australia (AS Level 10, The Exchange Centre, 20 Bridge Street, Sydney, GPO Box 476, Sydney NSW 2001, + 61 2 9237 6171 <http://www.stadards.org.au>), British Standards Institution (BSI, 389 Chiswick High Road, London, W4 4AL, United Kingdom, + 44 (0)20 8996 9001, <http://www.bsigroup.com>), Canadian Standards Association (CSA 5060 Spectrum Way, Suite 100, Mississauga, Ontario L4W 5N6, Canada, 800-463-6727, <http://www.csa.ca>), European Committee for Standardization (CEN CENELEC Management Centre Avenue Marnix 17 B-1000 Brussels, Belgium + 32 2 550 08 11, <http://www.cen.eu/cen>), and German Engineering Standards (VDI VDI Guidelines Department, P.O. Box 10 11 39 40002, Duesseldorf, Germany, + 49 211 6214-230, <http://www.vdi.eu>). The types of standards that are not considered VCS are standards developed by: The United States, *e.g.*, California (CARB) and Texas (TCEQ); industry groups, such as American Petroleum Institute (API), Gas Processors Association (GPA), and Gas Research Institute (GRI); and other branches of the U.S. government, *e.g.*, Department of Defense (DOD) and Department of Transportation (DOT). This does not preclude EPA from using standards developed by groups that are not VCS bodies within their rule. When this occurs, EPA has done searches and reviews for VCS equivalent to these non-EPA methods.

*Waste heat boiler* means a device that recovers normally unused energy (*i.e.*, hot exhaust gas) and converts it to usable heat. Waste heat boilers are also referred to as heat recovery steam generators. Waste heat boilers are heat exchangers generating steam from incoming hot exhaust gas from an industrial (*e.g.*, thermal oxidizer, kiln, furnace) or power (*e.g.*, combustion turbine, engine) equipment. Duct burners are sometimes used to increase the temperature of the incoming hot exhaust gas.

*Waste heat process heater* means an enclosed device that recovers normally unused energy (*i.e.*, hot exhaust gas) and converts it to usable heat. Waste heat process heaters are also referred to as recuperative process heaters. This definition includes both fired and unfired waste heat process heaters.

*Wet scrubber* means any add-on air pollution control device that mixes an aqueous stream or slurry with the exhaust gases from a boiler or process heater to control emissions of particulate matter or to absorb and neutralize acid gases, such as hydrogen chloride. A wet scrubber creates an aqueous stream or slurry as a byproduct of the emissions control process.

*Work practice standard* means any design, equipment, work practice, or operational standard, or combination thereof, that is promulgated pursuant to section 112(h) of the Clean Air Act.

[78 FR 15664, Mar. 21, 2011, as amended at 78 FR 7163, Jan. 31, 2013; 80 FR 72817, Nov. 20, 2015; 87 FR 60846, Oct. 6, 2022]

**Table 1 to Subpart DDDDD of Part 63 - Emission Limits for New or Reconstructed Boilers and Process Heaters <sup>c</sup>**

As stated in § 63.7500, you must comply with the following applicable emission limits:

Table 1 to Subpart DDDDD of Part 63 - Emission Limits for New or Reconstructed Boilers and Process Heaters <sup>c</sup>

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling
1. Units in all subcategories designed to burn solid fuel	a. HCl	2.1E-04 <sup>a</sup> lb per MMBtu of heat input	2.9E-04 <sup>a</sup> lb per MMBtu of steam output or 2.7E-03 <sup>a</sup> lb per MWh	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
	b. Mercury	8.0E-07 <sup>a</sup> lb per MMBtu of heat input	8.7E-07 <sup>a</sup> lb per MMBtu of steam output or 1.1E-05 <sup>a</sup> lb per MWh	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 <sup>b</sup> collect a minimum of 4 dscm.
2. Units designed to burn coal/solid fossil fuel	a. Filterable PM (or TSM)	1.1E-03 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)	1.1E-03 lb per MMBtu of steam output or 1.4E-02 lb per MWh; or (2.7E-05 lb per MMBtu of steam output or 2.9E-04 lb per MWh)	Collect a minimum of 3 dscm per run.
3. Pulverized coal boilers designed to burn coal/solid fossil fuel	a. Carbon monoxide (CO) (or CEMS)	130 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3-percent oxygen, <sup>d</sup> 30-day rolling average)	0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling
4. Stokers/others designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3-percent oxygen <sup>d</sup> , 30-day rolling average)	0.12 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
5. Fluidized bed units designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3-percent oxygen, <sup>d</sup> 30-day rolling average)	0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3-percent oxygen, <sup>d</sup> 30-day rolling average)	1.2E-01 lb per MMBtu of steam output or 1.5 lb per MWh; 3-run average	1 hr minimum sampling time.
7. Stokers/sloped grate/others designed to burn wet biomass fuel	a. CO (or CEMS)	590 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (390 ppm by volume on a dry basis corrected to 3-percent oxygen, <sup>d</sup> 30-day rolling average)	6.1E-01 lb per MMBtu of steam output or 6.5 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.3E-02 lb per MMBtu of heat input; or (2.6E-05 lb per MMBtu of heat input)	1.4E-02 lb per MMBtu of steam output or 1.9E-01 lb per MWh; or (2.7E-05 lb per MMBtu of steam output or 3.7E-04 lb per MWh)	Collect a minimum of 2 dscm per run.
8. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel	a. CO	460 ppm by volume on a dry basis corrected to 3-percent oxygen	4.3E-01 lb per MMBtu of steam output or 5.1 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (5.0E-03 lb per MMBtu of heat input)	3.5E-02 lb per MMBtu of steam output or 4.2E-01 lb per MWh; or (5.2E-03 lb per MMBtu of steam output or 7.0E-02 lb per MWh)	Collect a minimum of 2 dscm per run.



If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling
9. Fluidized bed units designed to burn biomass/bio-based solids	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3-percent oxygen, <sup>d</sup> 30-day rolling average)	1.3E-01 lb per MMBtu of steam output or 1.5 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	4.1E-03 lb per MMBtu of heat input; or (8.4E-06 <sup>a</sup> lb per MMBtu of heat input)	5.0E-03 lb per MMBtu of steam output or 5.8E-02 lb per MWh; or (1.1E-05 <sup>a</sup> lb per MMBtu of steam output or 1.2E-04 <sup>a</sup> lb per MWh)	Collect a minimum of 3 dscm per run.
10. Suspension burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	220 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3-percent oxygen, <sup>d</sup> 10-day rolling average)	0.18 lb per MMBtu of steam output or 2.5 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (8.0E-03 lb per MMBtu of heat input)	3.1E-02 lb per MMBtu of steam output or 4.2E-01 lb per MWh; or (8.1E-03 lb per MMBtu of steam output or 1.2E-01 lb per MWh)	Collect a minimum of 2 dscm per run.
11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	330 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3-percent oxygen, <sup>d</sup> 10-day rolling average)	3.5E-01 lb per MMBtu of steam output or 3.6 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.5E-03 lb per MMBtu of heat input; or (3.9E-05 lb per MMBtu of heat input)	3.4E-03 lb per MMBtu of steam output or 3.5E-02 lb per MWh; or (5.2E-05 lb per MMBtu of steam output or 5.5E-04 lb per MWh)	Collect a minimum of 3 dscm per run.
12. Fuel cell units designed to burn biomass/bio-based solids	a. CO	910 ppm by volume on a dry basis corrected to 3-percent oxygen	1.1 lb per MMBtu of steam output or 1.0E+01 lb per MWh	1 hr minimum sampling time.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling
	b. Filterable PM (or TSM)	1.1E-02 lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	2.0E-02 lb per MMBtu of steam output or 1.6E-01 lb per MWh; or (5.1E-05 lb per MMBtu of steam output or 4.1E-04 lb per MWh)	Collect a minimum of 2 dscm per run.
13. Hybrid suspension grate boiler designed to burn biomass/bio-based solids	a. CO (or CEMS)	180 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3-percent oxygen <sup>d</sup> , 30-day rolling average)	0.22 lb per MMBtu of steam output or 2.0 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.6E-02 lb per MMBtu of heat input; or (4.4E-04 lb per MMBtu of heat input)	3.3E-02 lb per MMBtu of steam output or 3.7E-01 lb per MWh; or (5.5E-04 lb per MMBtu of steam output or 6.2E-03 lb per MWh)	Collect a minimum of 3 dscm per run.
14. Units designed to burn liquid fuel	a. HCl	1.5E-04 <sup>a</sup> lb per MMBtu of heat input	1.7E-04 <sup>a</sup> lb per MMBtu of steam output or 2.1E-03 <sup>a</sup> lb per MWh	For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	4.8E-07 <sup>a</sup> lb per MMBtu of heat input	5.3E-07 <sup>a</sup> lb per MMBtu of steam output or 6.7E-06 <sup>a</sup> lb per MWh	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 <sup>b</sup> collect a minimum of 4 dscm.
15. Units designed to burn heavy liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.9E-03 lb per MMBtu of heat input; or (6.1E-06 <sup>a</sup> lb per MMBtu of heat input)	2.1E-03 lb per MMBtu of steam output or 2.7E-02 lb per MWh; or (6.7E-6 <sup>a</sup> lb per MMBtu of steam output or 8.5E-5 <sup>a</sup> lb per MWh)	Collect a minimum of 3 dscm per run.
16. Units designed to burn light liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen	0.13 lb per MMBtu of steam output or 1.4 lb per MWh	1 hr minimum sampling time.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling
	b. Filterable PM (or TSM)	1.1E-03 <sup>a</sup> lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	1.2E-03 <sup>a</sup> lb per MMBtu of steam output or 1.6E-02 <sup>a</sup> lb per MWh; or (3.2E-05 lb per MMBtu of steam output or 4.0E-04 lb per MWh)	Collect a minimum of 3 dscm per run.
17. Units designed to burn liquid fuel that are non-continental units	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average based on stack test	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.3E-02 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)	2.5E-02 lb per MMBtu of steam output or 3.2E-01 lb per MWh; or (9.4E-04 lb per MMBtu of steam output or 1.2E-02 lb per MWh)	Collect a minimum of 4 dscm per run.
18. Units designed to burn gas 2 (other) gases	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen	0.16 lb per MMBtu of steam output or 1.0 lb per MWh	1 hr minimum sampling time.
	b. HCl	1.7E-03 lb per MMBtu of heat input	2.9E-03 lb per MMBtu of steam output or 1.8E-02 lb per MWh	For M26A, collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E-06 lb per MMBtu of heat input	1.4E-05 lb per MMBtu of steam output or 8.3E-05 lb per MWh	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 <sup>p</sup> collect a minimum of 3 dscm.
	d. Filterable PM (or TSM)	7.3E-03 lb per MMBtu of heat input; or (2.1E-04 lb per MMBtu of heat input)	1.3E-02 lb per MMBtu of steam output or 7.6E-02 lb per MWh; or (3.5E-04 lb per MMBtu of steam output or 2.2E-03 lb per MWh)	Collect a minimum of 3 dscm per run.

<sup>a</sup> If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to § 63.7515 if all of the other provisions of § 63.7515 are met. For all other pollutants that do not contain a footnote "a", your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

<sup>b</sup> Incorporated by reference, see § 63.14.

<sup>c</sup> If your affected source is a new or reconstructed affected source that commenced construction or reconstruction after June 4, 2010, and before April 1, 2013, you may comply with the emission limits in Table 11, 12, or 13 to this subpart until January 31, 2016. On and after January 31, 2016, but before October 6, 2025 you may comply with the emission limits in Table 14 to this subpart. On and after October 6, 2025 you must comply with the emission limits in this Table 1.

<sup>d</sup> An owner or operator may determine compliance with the carbon monoxide emissions limit using CO<sub>2</sub> as a diluent correction in place of oxygen as described in § 63.7525(a)(1). EPA Method 19 F-factors in 40 CFR part 60, appendix A-7, and EPA Method 19 equations in 40 CFR part 60, appendix A-7, must be used to generate the appropriate CO<sub>2</sub> correction percentage for the fuel type burned in the unit and must also take into account that the 3-percent oxygen correction is to be done on a dry basis. The methodology must account for any CO<sub>2</sub> being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc. This methodology must be detailed in the site-specific monitoring plan developed according to § 63.7505(d).

[87 FR 60847, Oct. 6, 2022]

**Table 2 to Subpart DDDDD of Part 63 - Emission Limits for Existing Boilers and Process Heaters <sup>d</sup>**

As stated in § 63.7500, you must comply with the following applicable emission limits:

[Units with heat input capacity of 10 million Btu per hour or greater]

<b>If your boiler or process heater is in this subcategory . . .</b>	<b>For the following pollutants . . .</b>	<b>The emissions must not exceed the following emission limits, except during startup and shutdown . . .</b>	<b>The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .</b>	<b>Using this specified sampling volume or test run duration . . .</b>
1. Units in all subcategories designed to burn solid fuel	a. HCl	2.0E-02 lb per MMBtu of heat input	2.3E-02 lb per MMBtu of steam output or 0.26 lb per MWh	For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 120 liters per run.
	b. Mercury	5.4E-06 lb per MMBtu of heat input	6.2E-06 lb per MMBtu of steam output or 6.9E-05 lb per MWh	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 <sup>b</sup> collect a minimum of 3 dscm.
2. Units design to burn coal/solid fossil fuel	a. Filterable PM (or TSM)	3.9E-02 lb per MMBtu of heat input; or (5.3E-05 lb per MMBtu of heat input)	4.1E-02 lb per MMBtu of steam output or 4.8E-01 lb per MWh; or (5.6E-05 lb per MMBtu of steam output or 6.5E-04 lb per MWh)	Collect a minimum of 2 dscm per run.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
3. Pulverized coal boilers designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3-percent oxygen, <sup>c</sup> 30-day rolling average)	0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
4. Stokers/others designed to burn coal/solid fossil fuel	a. CO (or CEMS)	150 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3-percent oxygen, <sup>c</sup> 30-day rolling average)	0.14 lb per MMBtu of steam output or 1.6 lb per MWh; 3-run average	1 hr minimum sampling time.
5. Fluidized bed units designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3-percent oxygen, <sup>c</sup> 30-day rolling average)	0.12 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3-percent oxygen, <sup>c</sup> 30-day rolling average)	1.3E-01 lb per MMBtu of steam output or 1.5 lb per MWh; 3-run average	1 hr minimum sampling time.
7. Stokers/sloped grate/others designed to burn wet biomass fuel	a. CO (or CEMS)	1,100 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (720 ppm by volume on a dry basis corrected to 3-percent oxygen, <sup>c</sup> 30-day rolling average)	1.1 lb per MMBtu of steam output or 13 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.4E-02 lb per MMBtu of heat input; or (2.0E-04 lb per MMBtu of heat input)	4.0E-02 lb per MMBtu of steam output or 4.8E-01 lb per MWh; or (2.4E-04 lb per MMBtu of steam output or 2.8E-03 lb per MWh)	Collect a minimum of 2 dscm per run.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
8. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel	a. CO	460 ppm by volume on a dry basis corrected to 3-percent oxygen	4.2E-01 lb per MMBtu of steam output or 5.1 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.2E-01 lb per MMBtu of heat input; or (5.0E-03 lb per MMBtu of heat input)	3.7E-01 lb per MMBtu of steam output or 4.5 lb per MWh; or (5.9E-03 lb per MMBtu of steam output or 7.0E-02 lb per MWh)	Collect a minimum of 1 dscm per run.
9. Fluidized bed units designed to burn biomass/bio-based solid	a. CO (or CEMS)	210 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3-percent oxygen, <sup>c</sup> 30-day rolling average)	2.1E-01 lb per MMBtu of steam output or 2.3 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	7.4E-03 lb per MMBtu of heat input; or (6.4E-05 lb per MMBtu of heat input)	9.2E-03 lb per MMBtu of steam output or 0.11 lb per MWh; or (8.0E-05 lb per MMBtu of steam output or 9.0E-04 lb per MWh)	Collect a minimum of 1 dscm per run.
10. Suspension burners designed to burn biomass/bio-based solid	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3-percent oxygen, <sup>c</sup> 10-day rolling average)	1.9 lb per MMBtu of steam output or 27 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	4.1E-02 lb per MMBtu of heat input; or (8.0E-03 lb per MMBtu of heat input)	4.2E-02 lb per MMBtu of steam output or 5.8E-01 lb per MWh; or (8.1E-03 lb per MMBtu of steam output or 0.12 lb per MWh)	Collect a minimum of 2 dscm per run.
11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solid	a. CO (or CEMS)	770 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3-percent oxygen, <sup>c</sup> 10-day rolling average)	8.4E-01 lb per MMBtu of steam output or 8.4 lb per MWh; 3-run average	1 hr minimum sampling time.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
	b. Filterable PM (or TSM)	1.8E-01 lb per MMBtu of heat input; or (2.0E-03 lb per MMBtu of heat input)	2.5E-01 lb per MMBtu of steam output or 2.6 lb per MWh; or (2.8E-03 lb per MMBtu of steam output or 2.8E-02 lb per MWh)	Collect a minimum of 1 dscm per run.
12. Fuel cell units designed to burn biomass/bio-based solid	a. CO	1,100 ppm by volume on a dry basis corrected to 3-percent oxygen	2.4 lb per MMBtu of steam output or 12 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E-02 lb per MMBtu of heat input; or (5.8E-03 lb per MMBtu of heat input)	5.5E-02 lb per MMBtu of steam output or 2.8E-01 lb per MWh; or (1.6E-02 lb per MMBtu of steam output or 8.1E-02 lb per MWh)	Collect a minimum of 2 dscm per run.
13. Hybrid suspension grate units designed to burn biomass/bio-based solid	a. CO (or CEMS)	3,500 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3-percent oxygen, <sup>c</sup> 30-day rolling average)	3.5 lb per MMBtu of steam output or 39 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	4.4E-01 lb per MMBtu of heat input; or (4.5E-04 lb per MMBtu of heat input)	5.5E-01 lb per MMBtu of steam output or 6.2 lb per MWh; or (5.7E-04 lb per MMBtu of steam output or 6.3E-03 lb per MWh)	Collect a minimum of 1 dscm per run.
14. Units designed to burn liquid fuel	a. HCl	1.1E-03 lb per MMBtu of heat input	1.4E-03 lb per MMBtu of steam output or 1.6E-02 lb per MWh	For M26A, collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	7.3E-07 lb per MMBtu of heat input	8.8E-07 lb per MMBtu of steam output or 1.1E-05 lb per MWh	For M29, collect a minimum of 3 dscm per run; for M30A or M30B collect a minimum sample as specified in the method, for ASTM D6784 <sup>b</sup> collect a minimum of 2 dscm.
15. Units designed to burn heavy liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
	b. Filterable PM (or TSM)	5.9E-02 lb per MMBtu of heat input; or (2.0E-04 lb per MMBtu of heat input)	7.2E-02 lb per MMBtu of steam output or 8.2E-01 lb per MWh; or (2.5E-04 lb per MMBtu of steam output or 2.8E-03 lb per MWh)	Collect a minimum of 1 dscm per run.
16. Units designed to burn light liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen	0.13 lb per MMBtu of steam output or 1.4 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	7.9E-03 lb per MMBtu of heat input; or (6.2E-05 lb per MMBtu of heat input)	9.6E-03 lb per MMBtu of steam output or 1.1E-01 lb per MWh; or (7.5E-05 lb per MMBtu of steam output or 8.6E-04 lb per MWh)	Collect a minimum of 3 dscm per run.
17. Units designed to burn liquid fuel that are non-continental units	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average based on stack test	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.2E-01 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)	2.7E-01 lb per MMBtu of steam output or 3.1 lb per MWh; or (1.1E-03 lb per MMBtu of steam output or 1.2E-02 lb per MWh)	Collect a minimum of 2 dscm per run.
18. Units designed to burn gas 2 (other) gases	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen	0.16 lb per MMBtu of steam output or 1.0 lb per MWh	1 hr minimum sampling time.
	b. HCl	1.7E-03 lb per MMBtu of heat input	2.9E-03 lb per MMBtu of steam output or 1.8E-02 lb per MWh	For M26A, collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E-06 lb per MMBtu of heat input	1.4E-05 lb per MMBtu of steam output or 8.3E-05 lb per MWh	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 <sup>b</sup> collect a minimum of 2 dscm.



If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
	d. Filterable PM (or TSM)	7.3E-03 lb per MMBtu of heat input or (2.1E-04 lb per MMBtu of heat input)	1.3E-02 lb per MMBtu of steam output or 7.6E-02 lb per MWh; or (3.5E-04 lb per MMBtu of steam output or 2.2E-03 lb per MWh)	Collect a minimum of 3 dscm per run.

<sup>a</sup> If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to § 63.7515 if all of the other provisions of § 63.7515 are met. For all other pollutants that do not contain a footnote a, your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

<sup>b</sup> Incorporated by reference, see § 63.14.

<sup>c</sup> An owner or operator may determine compliance with the carbon monoxide emissions limit be determined using CO<sub>2</sub> as a diluent correction in place of oxygen as described in § 63.7525(a)(1). EPA Method 19 F-factors in 40 CFR part 60, appendix A-7, and EPA Method 19 equations in 40 CFR part 60, appendix A-7, must be used to generate the appropriate CO<sub>2</sub> correction percentage for the fuel type burned in the unit and must also take into account that the 3-percent oxygen correction is to be done on a dry basis. The methodology must account for any CO<sub>2</sub> being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc. This methodology must be detailed in the site-specific monitoring plan developed according to § 63.7505(d).

<sup>d</sup> Before October 6, 2025 you may comply with the emission limits in Table 15 to this subpart. On and after October 6, 2025], you must comply with the emission limits in this Table 2.

[87 FR 60849, Oct. 6, 2022]

**Table 3 to Subpart DDDDD of Part 63 - Work Practice Standards**

As stated in § 63.7500, you must comply with the following applicable work practice standards:

If your unit is . . .	You must meet the following . . .
1. A new or existing boiler or process heater with a continuous oxygen trim system that maintains an optimum air to fuel ratio, or a heat input capacity of less than or equal to 5 million Btu per hour in any of the following subcategories: unit designed to burn gas 1; unit designed to burn gas 2 (other); or unit designed to burn light liquid, or a limited use boiler or process heater	Conduct a tune-up of the boiler or process heater every 5 years as specified in § 63.7540.

If your unit is . . .	You must meet the following . . .
<p>2. A new or existing boiler or process heater without a continuous oxygen trim system and with heat input capacity of less than 10 million Btu per hour in the unit designed to burn heavy liquid or unit designed to burn solid fuel subcategories; or a new or existing boiler or process heater with heat input capacity of less than 10 million Btu per hour, but greater than 5 million Btu per hour, in any of the following subcategories: unit designed to burn gas 1; unit designed to burn gas 2 (other); or unit designed to burn light liquid</p>	<p>Conduct a tune-up of the boiler or process heater biennially as specified in § 63.7540.</p>
<p>3. A new or existing boiler or process heater without a continuous oxygen trim system and with heat input capacity of 10 million Btu per hour or greater</p>	<p>Conduct a tune-up of the boiler or process heater annually as specified in § 63.7540. Units in either the Gas 1 or Metal Process Furnace subcategories will conduct this tune-up as a work practice for all regulated emissions under this subpart. Units in all other subcategories will conduct this tune-up as a work practice for dioxins/furans.</p>
<p>4. An existing boiler or process heater located at a major source facility, not including limited use units</p>	<p>Must have a one-time energy assessment performed by a qualified energy assessor. An energy assessment completed on or after January 1, 2008, that meets or is amended to meet the energy assessment requirements in this table, satisfies the energy assessment requirement. A facility that operated under an energy management program developed according to the ENERGY STAR guidelines for energy management or compatible with ISO 50001 for at least one year between January 1, 2008 and the compliance date specified in § 63.7495 that includes the affected units also satisfies the energy assessment requirement. The energy assessment must include the following with extent of the evaluation for items a. to e. appropriate for the on-site technical hours listed in § 63.7575:</p>
	<p>a. A visual inspection of the boiler or process heater system.</p>
	<p>b. An evaluation of operating characteristics of the boiler or process heater systems, specifications of energy using systems, operating and maintenance procedures, and unusual operating constraints.</p>
	<p>c. An inventory of major energy use systems consuming energy from affected boilers and process heaters and which are under the control of the boiler/process heater owner/operator.</p>
	<p>d. A review of available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage.</p>
	<p>e. A review of the facility's energy management program and provide recommendations for improvements consistent with the definition of energy management program, if identified.</p>
	<p>f. A list of cost-effective energy conservation measures that are within the facility's control.</p>
	<p>g. A list of the energy savings potential of the energy conservation measures identified.</p>

If your unit is . . .	You must meet the following . . .
	<p>h. A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments.</p>
<p>5. An existing or new boiler or process heater subject to emission limits in Table 1 or 2 or 11 through 15 to this subpart during startup</p>	<p>a. You must operate all CMS during startup. b. For startup of a boiler or process heater, you must use one or a combination of the following clean fuels: natural gas, synthetic natural gas, propane, other Gas 1 fuels, distillate oil, syngas, ultra-low sulfur diesel, fuel oil-soaked rags, kerosene, hydrogen, paper, cardboard, refinery gas, liquefied petroleum gas, clean dry biomass, and any fuels meeting the appropriate HCl, mercury and TSM emission standards by fuel analysis.</p>
	<p>c. You have the option of complying using either of the following work practice standards. (1) If you choose to comply using paragraph (1) of the definition of "startup" in § 63.7575, once you start firing fuels that are not clean fuels you must vent emissions to the main stack(s) and engage all of the applicable control devices except limestone injection in fluidized bed combustion (FBC) boilers, dry scrubber, fabric filter, and selective catalytic reduction (SCR). You must start your limestone injection in FBC boilers, dry scrubber, fabric filter, and SCR systems as expeditiously as possible. Startup ends when steam or heat is supplied for any purpose, OR (2) If you choose to comply using paragraph (2) of the definition of "startup" in § 63.7575, once you start to feed fuels that are not clean fuels, you must vent emissions to the main stack(s) and engage all of the applicable control devices so as to comply with the emission limits within 4 hours of start of supplying useful thermal energy. You must engage and operate PM control within one hour of first feeding fuels that are not clean fuels<sup>a</sup>. You must start all applicable control devices as expeditiously as possible, but, in any case, when necessary to comply with other standards applicable to the source by a permit limit or a rule other than this subpart that require operation of the control devices. You must develop and implement a written startup and shutdown plan, as specified in § 63.7505(e).</p>
	<p>d. You must comply with all applicable emission limits at all times except during startup and shutdown periods at which time you must meet this work practice. You must collect monitoring data during periods of startup, as specified in § 63.7535(b). You must keep records during periods of startup. You must provide reports concerning activities and periods of startup, as specified in § 63.7555.</p>
<p>6. An existing or new boiler or process heater subject to emission limits in Table 1 or 2 or Tables 11 through 15 to this subpart during shutdown</p>	<p>You must operate all CMS during shutdown. While firing fuels that are not clean fuels during shutdown, you must vent emissions to the main stack(s) and operate all applicable control devices, except limestone injection in FBC boilers, dry scrubber, fabric filter, and SCR but, in any case, when necessary to comply with other standards applicable to the source that require operation of the control device.</p>

If your unit is . . .	You must meet the following . . .
	If, in addition to the fuel used prior to initiation of shutdown, another fuel must be used to support the shutdown process, that additional fuel must be one or a combination of the following clean fuels: Natural gas, synthetic natural gas, propane, other Gas 1 fuels, distillate oil, syngas, ultra-low sulfur diesel, refinery gas, and liquefied petroleum gas.
	You must comply with all applicable emissions limits at all times except for startup or shutdown periods conforming with this work practice. You must collect monitoring data during periods of shutdown, as specified in § 63.7535(b). You must keep records during periods of shutdown. You must provide reports concerning activities and periods of shutdown, as specified in § 63.7555.

<sup>a</sup> As specified in § 63.7555(d)(13), the source may request an alternative timeframe with the PM controls requirement to the permitting authority (state, local, or tribal agency) that has been delegated authority for this subpart by EPA. The source must provide evidence that (1) it is unable to safely engage and operate the PM control(s) to meet the “fuel firing + 1 hour” requirement and (2) the PM control device is appropriately designed and sized to meet the filterable PM emission limit. It is acknowledged that there may be another control device that has been installed other than ESP that provides additional PM control (e.g., scrubber).

[87 FR 60852, Oct. 6, 2022]

**Table 4 to Subpart DDDDD of Part 63 - Operating Limits for Boilers and Process Heaters**

As stated in § 63.7500, you must comply with the applicable operating limits:

Table 4 to Subpart DDDDD of Part 63 - Operating Limits for Boilers and Process Heaters

When complying with a numerical emission limit under Table 1, 2, 11, 12, 13, 14, or 15 of this subpart using . . .	You must meet these operating limits. . .
1. Wet PM scrubber control on a boiler or process heater not using a PM CPMS	Maintain the 30-day rolling average pressure drop and the 30-day rolling average liquid flow rate at or above the lowest one-hour average pressure drop and the lowest one-hour average liquid flow rate, respectively, measured during the performance test demonstrating compliance with the PM emission limitation according to § 63.7530(b) and Table 7 to this subpart.
2. Wet acid gas (HCl) scrubber <sup>a</sup> control on a boiler or process heater not using a HCl CEMS	Maintain the 30-day rolling average effluent pH at or above the lowest one-hour average pH and the 30-day rolling average liquid flow rate at or above the lowest one-hour average liquid flow rate measured during the performance test demonstrating compliance with the HCl emission limitation according to § 63.7530(b) and Table 7 to this subpart.
3. Fabric filter control on a boiler or process heater not using a PM CPMS	a. Maintain opacity to less than or equal to 10 percent opacity or the highest hourly average opacity reading measured during the performance test run demonstrating compliance with the PM (or TSM) emission limitation (daily block average); or
	b. Install and operate a bag leak detection system according to § 63.7525 and operate the fabric filter such that the bag leak detection system alert is not activated more than 5 percent of the operating time during each 6-month period.

When complying with a numerical emission limit under Table 1, 2, 11, 12, 13, 14, or 15 of this subpart using . . .	You must meet these operating limits. . .
4. Electrostatic precipitator control on a boiler or process heater not using a PM CPMS	a. This option is for boilers and process heaters that operate dry control systems ( <i>i.e.</i> , an ESP without a wet scrubber). Existing and new boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity or the highest hourly average opacity reading measured during the performance test run demonstrating compliance with the PM (or TSM) emission limitation (daily block average).
	b. This option is only for boilers and process heaters not subject to PM CPMS or continuous compliance with an opacity limit ( <i>i.e.</i> , dry ESP). Maintain the 30-day rolling average total secondary electric power input of the electrostatic precipitator at or above the operating limits established during the performance test according to § 63.7530(b) and Table 7 to this subpart.
5. Dry scrubber or carbon injection control on a boiler or process heater not using a mercury CEMS	Maintain the minimum sorbent or carbon injection rate as defined in § 63.7575 of this subpart.
6. Any other add-on air pollution control type on a boiler or process heater not using a PM CPMS	This option is for boilers and process heaters that operate dry control systems. Existing and new boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity or the highest hourly average opacity reading measured during the performance test run demonstrating compliance with the PM (or TSM) emission limitation (daily block average).
7. Performance testing	For boilers and process heaters that demonstrate compliance with a performance test, maintain the 30-day rolling average operating load of each unit such that it does not exceed 110 percent of the highest hourly average operating load recorded during the performance test.
8. Oxygen analyzer system	For boilers and process heaters subject to a CO emission limit that demonstrate compliance with an O <sub>2</sub> analyzer system as specified in § 63.7525(a), maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen concentration measured during the CO performance test, as specified in Table 8. This requirement does not apply to units that install an oxygen trim system since these units will set the trim system to the level specified in § 63.7525(a).
9. SO <sub>2</sub> CEMS	For boilers or process heaters subject to an HCl emission limit that demonstrate compliance with an SO <sub>2</sub> CEMS, maintain the 30-day rolling average SO <sub>2</sub> emission rate at or below the highest hourly average SO <sub>2</sub> concentration measured during the HCl performance test, as specified in Table 8.

<sup>a</sup> A wet acid gas scrubber is a control device that removes acid gases by contacting the combustion gas with an alkaline slurry or solution. Alkaline reagents include, but not limited to, lime, limestone and sodium.

**Table 5 to Subpart DDDDD of Part 63 - Performance Testing Requirements**

As stated in § 63.7520, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources:

<b>To conduct a performance test for the following pollutant . . .</b>	<b>You must . . .</b>	<b>Using, as appropriate . . .</b>
1. Filterable PM	a. Select sampling ports location and the number of traverse points	Method 1 at 40 CFR part 60, appendix A-1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2F, or 2G at 40 CFR part 60, appendix A-1 or A-2 to part 60 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981. <sup>a</sup>
	d. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
	e. Measure the PM emission concentration	Method 5 or 17 (positive pressure fabric filters must use Method 5D) at 40 CFR part 60, appendix A-3 or A-6 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates	Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter.
2. TSM	a. Select sampling ports location and the number of traverse points	Method 1 at 40 CFR part 60, appendix A-1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2F, or 2G at 40 CFR part 60, appendix A-1 or A-2 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A-1 of this chapter, or ANSI/ASME PTC 19.10-1981. <sup>a</sup>
	d. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
	e. Measure the TSM emission concentration	Method 29 at 40 CFR part 60, appendix A-8 of this chapter
	f. Convert emissions concentration to lb per MMBtu emission rates	Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter.
3. Hydrogen chloride	a. Select sampling ports location and the number of traverse points	Method 1 at 40 CFR part 60, appendix A-1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2F, or 2G at 40 CFR part 60, appendix A-2 of this chapter.

<b>To conduct a performance test for the following pollutant . . .</b>	<b>You must. . .</b>	<b>Using, as appropriate . . .</b>
	c. Determine oxygen or carbon dioxide concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A-2 of this chapter, or ANSI/ASME PTC 19.10-1981. <sup>a</sup>
	d. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
	e. Measure the hydrogen chloride emission concentration	Method 26 or 26A (M26 or M26A) at 40 CFR part 60, appendix A-8 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates	Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter.
4. Mercury	a. Select sampling ports location and the number of traverse points	Method 1 at 40 CFR part 60, appendix A-1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2F, or 2G at 40 CFR part 60, appendix A-1 or A-2 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A-1 of this chapter, or ANSI/ASME PTC 19.10-1981. <sup>a</sup>
	d. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
	e. Measure the mercury emission concentration	Method 29, 30A, or 30B (M29, M30A, or M30B) at 40 CFR part 60, appendix A-8 of this chapter or Method 101A at 40 CFR part 61, appendix B of this chapter, or ASTM Method D6784. <sup>a</sup>
	f. Convert emissions concentration to lb per MMBtu emission rates	Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter.
5. CO	a. Select the sampling ports location and the number of traverse points	Method 1 at 40 CFR part 60, appendix A-1 of this chapter.
	b. Determine oxygen concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A-3 of this chapter, or ASTM D6522-00 (Reapproved 2005), or ANSI/ASME PTC 19.10-1981. <sup>a</sup>
	c. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
	d. Measure the CO emission concentration	Method 10 at 40 CFR part 60, appendix A-4 of this chapter. Use a measurement span value of 2 times the concentration of the applicable emission limit.

<sup>a</sup> Incorporated by reference, see § 63.14.

**Table 6 to Subpart DDDDD of Part 63 - Fuel Analysis Requirements**

As stated in § 63.7521, you must comply with the following requirements for fuel analysis testing for existing, new or reconstructed affected sources. However, equivalent methods (as defined in § 63.7575) may be used in lieu of the prescribed methods at the discretion of the source owner or operator:

<b>To conduct a fuel analysis for the following pollutant . . .</b>	<b>You must . . .</b>	<b>Using . . .</b>
1. Mercury	a. Collect fuel samples	Procedure in § 63.7521(c) or ASTM D5192 <sup>a</sup> , or ASTM D7430 <sup>a</sup> , or ASTM D6883 <sup>a</sup> , or ASTM D2234/D2234M <sup>a</sup> (for coal) or EPA 1631 or EPA 1631E or ASTM D6323 <sup>a</sup> (for solid), or EPA 821-R-01-013 (for liquid or solid), or ASTM D4177 <sup>a</sup> (for liquid), or ASTM D4057 <sup>a</sup> (for liquid), or equivalent.
	b. Composite fuel samples	Procedure in § 63.7521(d) or equivalent.
	c. Prepare composited fuel samples	EPA SW-846-3050B <sup>a</sup> (for solid samples), ASTM D2013/D2013M <sup>a</sup> (for coal), ASTM D5198 <sup>a</sup> (for biomass), or EPA 3050 <sup>a</sup> (for solid fuel), or EPA 821-R-01-013 <sup>a</sup> (for liquid or solid), or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865 <sup>a</sup> (for coal) or ASTM E711 <sup>a</sup> (for biomass), or ASTM D5864 <sup>a</sup> for liquids and other solids, or ASTM D240 <sup>a</sup> or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173 <sup>a</sup> , ASTM E871 <sup>a</sup> , or ASTM D5864 <sup>a</sup> , or ASTM D240 <sup>a</sup> , or ASTM D95 <sup>a</sup> (for liquid fuels), or ASTM D4006 <sup>a</sup> (for liquid fuels), or equivalent.
	f. Measure mercury concentration in fuel sample	ASTM D6722 <sup>a</sup> (for coal), EPA SW-846-7471B <sup>a</sup> or EPA 1631 or EPA 1631E <sup>a</sup> (for solid samples), or EPA SW-846-7470A <sup>a</sup> or EPA SW-846-7471B <sup>a</sup> (for liquid samples), or EPA 821-R-01-013 <sup>a</sup> (for liquid or solid), or equivalent.
	g. Convert concentration into units of pounds of mercury per MMBtu of heat content	For fuel mixtures use Equation 8 in § 63.7530.
2. HCl	a. Collect fuel samples	Procedure in § 63.7521(c) or ASTM D5192 <sup>a</sup> , or ASTM D7430 <sup>a</sup> , or ASTM D6883 <sup>a</sup> , or ASTM D2234/D2234M <sup>a</sup> (for coal) or ASTM D6323 <sup>a</sup> (for coal or biomass), ASTM D4177 <sup>a</sup> (for liquid fuels) or ASTM D4057 <sup>a</sup> (for liquid fuels), or equivalent.
	b. Composite fuel samples	Procedure in § 63.7521(d) or equivalent.
	c. Prepare composited fuel samples	EPA SW-846-3050B <sup>a</sup> (for solid samples), ASTM D2013/D2013M <sup>a</sup> (for coal), or ASTM D5198 <sup>a</sup> (for biomass), or EPA 3050 <sup>a</sup> or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865 <sup>a</sup> (for coal) or ASTM E711 <sup>a</sup> (for biomass), ASTM D5864 <sup>a</sup> , ASTM D240 <sup>a</sup> or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173 <sup>a</sup> or ASTM E871 <sup>a</sup> , or D5864 <sup>a</sup> , or ASTM D240 <sup>a</sup> , or ASTM D95 <sup>a</sup> (for liquid fuels), or ASTM D4006 <sup>a</sup> (for liquid fuels), or equivalent.
	f. Measure chlorine concentration in fuel sample	EPA SW-846-9250 <sup>a</sup> , ASTM D6721 <sup>a</sup> , ASTM D4208 <sup>a</sup> (for coal), or EPA SW-846-5050 <sup>a</sup> or ASTM E776 <sup>a</sup> (for solid fuel), or EPA SW-846-9056 <sup>a</sup> or SW-846-9076 <sup>a</sup> (for solids or liquids) or equivalent.



<b>To conduct a fuel analysis for the following pollutant . . .</b>	<b>You must . . .</b>	<b>Using . . .</b>
	g. Convert concentrations into units of pounds of HCl per MMBtu of heat content	For fuel mixtures use Equation 7 in § 63.7530 and convert from chlorine to HCl by multiplying by 1.028.
3. Mercury Fuel Specification for other gas 1 fuels	a. Measure mercury concentration in the fuel sample and convert to units of micrograms per cubic meter, or	Method 30B (M30B) at 40 CFR part 60, appendix A-8 of this chapter or ASTM D5954 <sup>a</sup> , ASTM D6350 <sup>a</sup> , ISO 6978-1:2003(E) <sup>a</sup> , or ISO 6978-2:2003(E) <sup>a</sup> , or EPA-1631 <sup>a</sup> or equivalent.
	b. Measure mercury concentration in the exhaust gas when firing only the other gas 1 fuel is fired in the boiler or process heater	Method 29, 30A, or 30B (M29, M30A, or M30B) at 40 CFR part 60, appendix A-8 of this chapter or Method 101A or Method 102 at 40 CFR part 61, appendix B of this chapter, or ASTM Method D6784 <sup>a</sup> or equivalent.
4. TSM	a. Collect fuel samples	Procedure in § 63.7521(c) or ASTM D5192 <sup>a</sup> , or ASTM D7430 <sup>a</sup> , or ASTM D6883 <sup>a</sup> , or ASTM D2234/D2234M <sup>a</sup> (for coal) or ASTM D6323 <sup>a</sup> (for coal or biomass), or ASTM D4177 <sup>a</sup> , (for liquid fuels), or ASTM D4057 <sup>a</sup> (for liquid fuels), or equivalent.
	b. Composite fuel samples	Procedure in § 63.7521(d) or equivalent.
	c. Prepare composited fuel samples	EPA SW-846-3050B <sup>a</sup> (for solid samples), ASTM D2013/D2013M <sup>a</sup> (for coal), ASTM D5198 <sup>a</sup> or TAPPI T266 <sup>a</sup> (for biomass), or EPA 3050 <sup>a</sup> or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865 <sup>a</sup> (for coal) or ASTM E711 <sup>a</sup> (for biomass), or ASTM D5864 <sup>a</sup> for liquids and other solids, or ASTM D240 <sup>a</sup> or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173 <sup>a</sup> or ASTM E871 <sup>a</sup> , or D5864 <sup>a</sup> , or ASTM D240 <sup>a</sup> , or ASTM D95 <sup>a</sup> (for liquid fuels), or ASTM D4006 <sup>a</sup> (for liquid fuels), or ASTM D4177 <sup>a</sup> (for liquid fuels) or ASTM D4057 <sup>a</sup> (for liquid fuels), or equivalent.
	f. Measure TSM concentration in fuel sample	ASTM D3683 <sup>a</sup> , or ASTM D4606 <sup>a</sup> , or ASTM D6357 <sup>a</sup> or EPA 200.8 <sup>a</sup> or EPA SW-846-6020 <sup>a</sup> , or EPA SW-846-6020A <sup>a</sup> , or EPA SW-846-6010C <sup>a</sup> , EPA 7060 <sup>a</sup> or EPA 7060A <sup>a</sup> (for arsenic only), or EPA SW-846-7740 <sup>a</sup> (for selenium only).
	g. Convert concentrations into units of pounds of TSM per MMBtu of heat content	For fuel mixtures use Equation 9 in § 63.7530.

<sup>a</sup> Incorporated by reference, see § 63.14.

**Table 7 to Subpart DDDDD of Part 63 - Establishing Operating Limits<sup>ab</sup>**

As stated in § 63.7520, you must comply with the following requirements for establishing operating limits:

Table 7 to Subpart DDDDD of Part 63 - Establishing Operating Limits<sup>ab</sup>

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements
1. PM, TSM, or mercury	a. Wet scrubber operating parameters	i. Establish a site-specific minimum scrubber pressure drop and minimum flow rate operating limit according to § 63.7530(b)	(1) Data from the scrubber pressure drop and liquid flow rate monitors and the PM, TSM, or mercury performance test	(a) You must collect scrubber pressure drop and liquid flow rate data every 15 minutes during the entire period of the performance tests.
				(b) Determine the lowest hourly average scrubber pressure drop and liquid flow rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.
	b. Electrostatic precipitator operating parameters (option only for units that operate wet scrubbers)	i. Establish a site-specific minimum total secondary electric power input according to § 63.7530(b)	(1) Data from the voltage and secondary amperage monitors during the PM or mercury performance test	(a) You must collect secondary voltage and secondary amperage for each ESP cell and calculate total secondary electric power input data every 15 minutes during the entire period of the performance tests.
				(b) Determine the average total secondary electric power input by computing the hourly averages using all of the 15-minute readings taken during each performance test.
	c. Opacity	i. Establish a site-specific maximum opacity level	(1) Data from the opacity monitoring system during the PM performance test	(a) You must collect opacity readings every 15 minutes during the entire period of the performance tests.
				(b) Determine the average hourly opacity reading by computing the hourly averages using all of the 15-minute readings taken during each performance test.

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements
				(c) Determine the highest hourly average opacity reading measured during the test run demonstrating compliance with the PM (or TSM) emission limitation.
2. HCl	a. Wet scrubber operating parameters	i. Establish site-specific minimum effluent pH and flow rate operating limits according to § 63.7530(b)	(1) Data from the pH and liquid flow-rate monitors and the HCl performance test	(a) You must collect pH and liquid flow-rate data every 15 minutes during the entire period of the performance tests.
				(b) Determine the hourly average pH and liquid flow rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.
	b. Dry scrubber operating parameters	i. Establish a site-specific minimum sorbent injection rate operating limit according to § 63.7530(b). If different acid gas sorbents are used during the HCl performance test, the average value for each sorbent becomes the site-specific operating limit for that sorbent	(1) Data from the sorbent injection rate monitors and HCl or mercury performance test	(a) You must collect sorbent injection rate data every 15 minutes during the entire period of the performance tests.
				(b) Determine the hourly average sorbent injection rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.
				(c) Determine the lowest hourly average of the three test run averages established during the performance test as your operating limit. When your unit operates at lower loads, multiply your sorbent injection rate by the load fraction, as defined in § 63.7575, to determine the required injection rate.

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements
	c. Alternative Maximum SO <sub>2</sub> emission rate	i. Establish a site-specific maximum SO <sub>2</sub> emission rate operating limit according to § 63.7530(b)	(1) Data from SO <sub>2</sub> CEMS and the HCl performance test	(a) You must collect the SO <sub>2</sub> emissions data according to § 63.7525(m) during the most recent HCl performance tests.
				(b) The maximum SO <sub>2</sub> emission rate is equal to the highest hourly average SO <sub>2</sub> emission rate measured during the most recent HCl performance tests.
3. Mercury	a. Activated carbon injection	i. Establish a site-specific minimum activated carbon injection rate operating limit according to § 63.7530(b)	(1) Data from the activated carbon rate monitors and mercury performance test	(a) You must collect activated carbon injection rate data every 15 minutes during the entire period of the performance tests.
				(b) Determine the hourly average activated carbon injection rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.
				(c) Determine the lowest hourly average established during the performance test as your operating limit. When your unit operates at lower loads, multiply your activated carbon injection rate by the load fraction, as defined in § 63.7575, to determine the required injection rate.
4. Carbon monoxide for which compliance is demonstrated by a performance test	a. Oxygen	i. Establish a unit-specific limit for minimum oxygen level according to § 63.7530(b)	(1) Data from the oxygen analyzer system specified in § 63.7525(a)	(a) You must collect oxygen data every 15 minutes during the entire period of the performance tests.
				(b) Determine the hourly average oxygen concentration by computing the hourly averages using all of the 15-minute readings taken during each performance test.

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements
				(c) Determine the lowest hourly average established during the performance test as your minimum operating limit.
5. Any pollutant for which compliance is demonstrated by a performance test	a. Boiler or process heater operating load	i. Establish a unit specific limit for maximum operating load according to § 63.7520(c)	(1) Data from the operating load monitors or from steam generation monitors	(a) You must collect operating load or steam generation data every 15 minutes during the entire period of the performance test.
				(b) Determine the average operating load by computing the hourly averages using all of the 15-minute readings taken during each performance test.
				(c) Determine the highest hourly average of the three test run averages during the performance test, and multiply this by 1.1 (110 percent) as your operating limit.

<sup>a</sup> Operating limits must be confirmed or reestablished during performance tests.

<sup>b</sup> If you conduct multiple performance tests, you must set the minimum liquid flow rate and pressure drop operating limits at the higher of the minimum values established during the performance tests. For a minimum oxygen level, if you conduct multiple performance tests, you must set the minimum oxygen level at the lower of the minimum values established during the performance tests. For maximum operating load, if you conduct multiple performance tests, you must set the maximum operating load at the lower of the maximum values established during the performance tests.

[87 FR 60853, Oct. 6, 2022]

**Table 8 to Subpart DDDDD of Part 63 - Demonstrating Continuous Compliance**

As stated in § 63.7540, you must show continuous compliance with the emission limitations for each boiler or process heater according to the following:

If you must meet the following operating limits or work practice standards . . .	You must demonstrate continuous compliance by . . .
1. Opacity	a. Collecting the opacity monitoring system data according to § 63.7525(c) and § 63.7535; and
	b. Reducing the opacity monitoring data to 6-minute averages; and
	c. Maintaining daily block average opacity to less than or equal to 10 percent or the highest hourly average opacity reading measured during the performance test run demonstrating compliance with the PM (or TSM) emission limitation.

If you must meet the following operating limits or work practice standards . . .	You must demonstrate continuous compliance by . . .
2. PM CPMS	a. Collecting the PM CPMS output data according to § 63.7525;
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average PM CPMS output data to less than the operating limit established during the performance test according to § 63.7530(b)(4).
3. Fabric Filter Bag Leak Detection Operation	Installing and operating a bag leak detection system according to § 63.7525 and operating the fabric filter such that the requirements in § 63.7540(a)(7) are met.
4. Wet Scrubber Pressure Drop and Liquid Flow-rate	a. Collecting the pressure drop and liquid flow rate monitoring system data according to §§ 63.7525 and 63.7535; and
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average pressure drop and liquid flow-rate at or above the operating limits established during the performance test according to § 63.7530(b).
5. Wet Scrubber pH	a. Collecting the pH monitoring system data according to §§ 63.7525 and 63.7535; and
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average pH at or above the operating limit established during the performance test according to § 63.7530(b).
6. Dry Scrubber Sorbent or Carbon Injection Rate	a. Collecting the sorbent or carbon injection rate monitoring system data for the dry scrubber according to §§ 63.7525 and 63.7535; and
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average sorbent or carbon injection rate at or above the minimum sorbent or carbon injection rate as defined in § 63.7575.
7. Electrostatic Precipitator Total Secondary Electric Power Input	a. Collecting the total secondary electric power input monitoring system data for the electrostatic precipitator according to §§ 63.7525 and 63.7535; and
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average total secondary electric power input at or above the operating limits established during the performance test according to § 63.7530(b).
8. Emission limits using fuel analysis	a. Conduct monthly fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart; and
	b. Reduce the data to 12-month rolling averages; and
	c. Maintain the 12-month rolling average at or below the applicable emission limit for HCl or mercury or TSM in Tables 1 and 2 or 11 through 15 to this subpart.
	d. Calculate the HCl, mercury, and/or TSM emission rate from the boiler or process heater in units of lb/MMBtu using Equation 15 and Equations 16, 17, and/or 18 in § 63.7530.
9. Oxygen content	a. Continuously monitor the oxygen content using an oxygen analyzer system according to § 63.7525(a). This requirement does not apply to units that install an oxygen trim system since these units will set the trim system to the level specified in § 63.7525(a)(7).
	b. Reducing the data to 30-day rolling averages; and

If you must meet the following operating limits or work practice standards . . .	You must demonstrate continuous compliance by . . .
	c. Maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen level measured during the CO performance test.
10. Boiler or process heater operating load	a. Collecting operating load data or steam generation data every 15 minutes. b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average operating load such that it does not exceed 110 percent of the highest hourly average operating load recorded during the performance test according to § 63.7520(c).
11. SO <sub>2</sub> emissions using SO <sub>2</sub> CEMS	a. Collecting the SO <sub>2</sub> CEMS output data according to § 63.7525;
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average SO <sub>2</sub> CEMS emission rate to a level at or below the highest hourly SO <sub>2</sub> rate measured during the HCl performance test according to § 63.7530.

[78 FR 7204, Jan. 31, 2013, as amended at 80 FR 72829, Nov. 20, 2015; 87 FR 60855, Oct. 6, 2022]

**Table 9 to Subpart DDDDD of Part 63 - Reporting Requirements**

As stated in § 63.7550, you must comply with the following requirements for reports:

You must submit a(n)	The report must contain . . .	You must submit the report . . .
1. Compliance report	a. Information required in § 63.7550(c)(1) through (5); and	Semiannually, annually, biennially, or every 5 years according to the requirements in § 63.7550(b).
	b. If there are no deviations from any emission limitation (emission limit and operating limit) that applies to you and there are no deviations from the requirements for work practice standards for periods of startup and shutdown in Table 3 to this subpart that apply to you, a statement that there were no deviations from the emission limitations and work practice standards during the reporting period. If there were no periods during which the CMSs, including continuous emissions monitoring system, continuous opacity monitoring system, and operating parameter monitoring systems, were out-of-control as specified in § 63.8(c)(7), a statement that there were no periods during which the CMSs were out-of-control during the reporting period; and	
	c. If you have a deviation from any emission limitation (emission limit and operating limit) where you are not using a CMS to comply with that emission limit or operating limit, or a deviation from a work practice standard for periods of startup and shutdown, during the reporting period, the report must contain the information in § 63.7550(d); and	
	d. If there were periods during which the CMSs, including continuous emissions monitoring system, continuous opacity monitoring system, and operating parameter monitoring systems, were out-of-control as specified in § 63.8(c)(7), or otherwise not operating, the report must contain the information in § 63.7550(e)	

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7205, Jan. 31, 2013; 80 FR 72830, Nov. 20, 2015]

**Table 10 to Subpart DDDDD of Part 63 - Applicability of General Provisions to Subpart DDDDD**

As stated in § 63.7565, you must comply with the applicable General Provisions according to the following:

<b>Citation</b>	<b>Subject</b>	<b>Applies to subpart DDDDD</b>
§ 63.1	Applicability	Yes.
§ 63.2	Definitions	Yes. Additional terms defined in § 63.7575
§ 63.3	Units and Abbreviations	Yes.
§ 63.4	Prohibited Activities and Circumvention	Yes.
§ 63.5	Preconstruction Review and Notification Requirements	Yes.
§ 63.6(a), (b)(1)-(b)(5), (b)(7), (c)	Compliance with Standards and Maintenance Requirements	Yes.
§ 63.6(e)(1)(i)	General duty to minimize emissions.	No. See § 63.7500(a)(3) for the general duty requirement.
§ 63.6(e)(1)(ii)	Requirement to correct malfunctions as soon as practicable.	No.
§ 63.6(e)(3)	Startup, shutdown, and malfunction plan requirements.	No.
§ 63.6(f)(1)	Startup, shutdown, and malfunction exemptions for compliance with non-opacity emission standards.	No.
§ 63.6(f)(2) and (3)	Compliance with non-opacity emission standards.	Yes.
§ 63.6(g)	Use of alternative standards	Yes, except § 63.7555(d)(13) specifies the procedure for application and approval of an alternative timeframe with the PM controls requirement in the startup work practice (2).
§ 63.6(h)(1)	Startup, shutdown, and malfunction exemptions to opacity standards.	No. See § 63.7500(a).
§ 63.6(h)(2) to (h)(9)	Determining compliance with opacity emission standards	No. Subpart DDDDD specifies opacity as an operating limit not an emission standard.
§ 63.6(i)	Extension of compliance	Yes. Note: Facilities may also request extensions of compliance for the installation of combined heat and power, waste heat recovery, or gas pipeline or fuel feeding infrastructure as a means of complying with this subpart.
§ 63.6(j)	Presidential exemption.	Yes.
§ 63.7(a), (b), (c), and (d)	Performance Testing Requirements	Yes.



Citation	Subject	Applies to subpart DDDDD
§ 63.7(e)(1)	Conditions for conducting performance tests	No. Subpart DDDDD specifies conditions for conducting performance tests at § 63.7520(a) to (c).
§ 63.7(e)(2)-(e)(9), (f), (g), and (h)	Performance Testing Requirements	Yes.
§ 63.8(a) and (b)	Applicability and Conduct of Monitoring	Yes.
§ 63.8(c)(1)	Operation and maintenance of CMS	Yes.
§ 63.8(c)(1)(i)	General duty to minimize emissions and CMS operation	No. See § 63.7500(a)(3).
§ 63.8(c)(1)(ii)	Operation and maintenance of CMS	Yes.
§ 63.8(c)(1)(iii)	Startup, shutdown, and malfunction plans for CMS	No.
§ 63.8(c)(2) to (c)(9)	Operation and maintenance of CMS	Yes.
§ 63.8(d)(1) and (2)	Monitoring Requirements, Quality Control Program	Yes.
§ 63.8(d)(3)	Written procedures for CMS	Yes, except for the last sentence, which refers to a startup, shutdown, and malfunction plan. Startup, shutdown, and malfunction plans are not required.
§ 63.8(e)	Performance evaluation of a CMS	Yes.
§ 63.8(f)	Use of an alternative monitoring method.	Yes.
§ 63.8(g)	Reduction of monitoring data	Yes.
§ 63.9	Notification Requirements	Yes.
§ 63.10(a), (b)(1)	Recordkeeping and Reporting Requirements	Yes.
§ 63.10(b)(2)(i)	Recordkeeping of occurrence and duration of startups or shutdowns	Yes.
§ 63.10(b)(2)(ii)	Recordkeeping of malfunctions	No. See § 63.7555(d)(7) for recordkeeping of occurrence and duration and § 63.7555(d)(8) for actions taken during malfunctions.
§ 63.10(b)(2)(iii)	Maintenance records	Yes.
§ 63.10(b)(2)(iv) and (v)	Actions taken to minimize emissions during startup, shutdown, or malfunction	No.
§ 63.10(b)(2)(vi)	Recordkeeping for CMS malfunctions	Yes.
§ 63.10(b)(2)(vii) to (xiv)	Other CMS requirements	Yes.

Citation	Subject	Applies to subpart DDDDD
§ 63.10(b)(3)	Recordkeeping requirements for applicability determinations	No.
§ 63.10(c)(1) to (9)	Recordkeeping for sources with CMS	Yes.
§ 63.10(c)(10) and (11)	Recording nature and cause of malfunctions, and corrective actions	No. See § 63.7555(d)(7) for recordkeeping of occurrence and duration and § 63.7555(d)(8) for actions taken during malfunctions.
§ 63.10(c)(12) and (13)	Recordkeeping for sources with CMS	Yes.
§ 63.10(c)(15)	Use of startup, shutdown, and malfunction plan	No.
§ 63.10(d)(1) and (2)	General reporting requirements	Yes.
§ 63.10(d)(3)	Reporting opacity or visible emission observation results	No.
§ 63.10(d)(4)	Progress reports under an extension of compliance	Yes.
§ 63.10(d)(5)	Startup, shutdown, and malfunction reports	No. See § 63.7550(c)(11) for malfunction reporting requirements.
§ 63.10(e)	Additional reporting requirements for sources with CMS	Yes.
§ 63.10(f)	Waiver of recordkeeping or reporting requirements	Yes.
§ 63.11	Control Device Requirements	No.
§ 63.12	State Authority and Delegation	Yes.
§ 63.13-63.16	Addresses, Incorporation by Reference, Availability of Information, Performance Track Provisions	Yes.
§ 63.1(a)(5),(a)(7)-(a)(9), (b)(2), (c)(3)-(4), (d), 63.6(b)(6), (c)(3), (c)(4), (d), (e)(2), (e)(3)(ii), (h)(3), (h)(5)(iv), 63.8(a)(3), 63.9(b)(3), (h)(4), 63.10(c)(2)-(4), (c)(9).	Reserved	No.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7205, Jan. 31, 2013; 80 FR 72830, Nov. 20, 2015]

**Table 11 to Subpart DDDDD of Part 63 - Alternative Emission Limits for New or Reconstructed Boilers and Process Heaters That Commenced Construction or Reconstruction After June 4, 2010, and Before May 20, 2011**

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel	a. HCl	0.022 lb per MMBtu of heat input	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
2. Units in all subcategories designed to burn solid fuel that combust at least 10 percent biomass/bio-based solids on an annual heat input basis and less than 10 percent coal/solid fossil fuels on an annual heat input basis	a. Mercury	8.0E-07 <sup>a</sup> lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 <sup>b</sup> collect a minimum of 4 dscm.
3. Units in all subcategories designed to burn solid fuel that combust at least 10 percent coal/solid fossil fuels on an annual heat input basis and less than 10 percent biomass/bio-based solids on an annual heat input basis	a. Mercury	2.0E-06 lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 <sup>b</sup> collect a minimum of 4 dscm.
4. Units design to burn coal/solid fossil fuel	a. Filterable PM (or TSM)	1.1E-03 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
5. Pulverized coal boilers designed to burn coal/solid fossil fuel	a. Carbon monoxide (CO) (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen, <sup>c</sup> 30-day rolling average)	1 hr minimum sampling time.
6. Stokers designed to burn coal/solid fossil fuel	a. CO (or CEMS).	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen, <sup>c</sup> 10-day rolling average)	1 hr minimum sampling time.
7. Fluidized bed units designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen, <sup>c</sup> 30-day rolling average)	1 hr minimum sampling time.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
8. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen, <sup>c</sup> 30-day rolling average)	1 hr minimum sampling time.
9. Stokers/sloped grate/others designed to burn wet biomass fuel	a. CO (or CEMS)	620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (390 ppm by volume on a dry basis corrected to 3 percent oxygen, <sup>c</sup> 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (2.6E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
10. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel	a. CO	560 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run
11. Fluidized bed units designed to burn biomass/bio-based solids	a. CO (or CEMS)	230 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen, <sup>c</sup> 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	9.8E-03 lb per MMBtu of heat input; or (8.3E-05 <sup>a</sup> lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run
12. Suspension burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen <sup>c</sup> 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
13. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	1,010 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen <sup>c</sup> 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	8.0E-03 lb per MMBtu of heat input; or (3.9E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
14. Fuel cell units designed to burn biomass/bio-based solids	a. CO	910 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E-02 lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
15. Hybrid suspension grate boiler designed to burn biomass/bio-based solids	a. CO (or CEMS)	1,100 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen, <sup>c</sup> 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.6E-02 lb per MMBtu of heat input; or (4.4E-04 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run
16. Units designed to burn liquid fuel	a. HCl	4.4E-04 lb per MMBtu of heat input	For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run
	b. Mercury.	4.8E-07 <sup>a</sup> lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 <sup>b</sup> collect a minimum of 4 dscm.
17. Units designed to burn heavy liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.3E-02 lb per MMBtu of heat input; or (7.5E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
18. Units designed to burn light liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
	b. Filterable PM (or TSM)	2.0E-03 <sup>a</sup> lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run
19. Units designed to burn liquid fuel that are non-continental units	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.3E-02 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)	Collect a minimum of 4 dscm per run
20. Units designed to burn gas 2 (other) gases	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. HCl	1.7E-03 lb per MMBtu of heat input	For M26A, Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E-06 lb per MMBtu of heat input	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 <sup>b</sup> collect a minimum of 3 dscm.
	d. Filterable PM (or TSM)	6.7E-03 lb per MMBtu of heat input; or (2.1E-04 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.

<sup>a</sup> If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to § 63.7515 if all of the other provision of § 63.7515 are met. For all other pollutants that do not contain a footnote “a”, your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

<sup>b</sup> Incorporated by reference, see § 63.14.

<sup>c</sup> An owner or operator may determine compliance with the carbon monoxide emissions limit using carbon dioxide as a diluent correction in place of oxygen as described in § 63.7525(a)(1). EPA Method 19 F-factors in 40 CFR part 60, appendix A-7, and EPA Method 19 equations in 40 CFR part 60, appendix A-7, must be used to generate the appropriate CO<sub>2</sub> correction percentage for the fuel type burned in the unit, and must also take into account that the 3% oxygen correction is to be done on a dry basis. The methodology must account for any CO<sub>2</sub> being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc. This methodology must be detailed in the site-specific monitoring plan developed according to § 63.7505(d).

**Table 12 to Subpart DDDDD of Part 63 - Alternative Emission Limits for New or Reconstructed Boilers and Process Heaters That Commenced Construction or Reconstruction After May 20, 2011, and Before December 23, 2011**

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel	a. HCl	0.022 lb per MMBtu of heat input	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
	b. Mercury	3.5E-06 <sup>a</sup> lb per MMBtu of heat input	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 <sup>b</sup> collect a minimum of 3 dscm.
2. Units design to burn coal/solid fossil fuel	a. Filterable PM (or TSM)	1.1E-03 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
3. Pulverized coal boilers designed to burn coal/solid fossil fuel	a. Carbon monoxide (CO) (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen, <sup>c</sup> 30-day rolling average)	1 hr minimum sampling time.
4. Stokers designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen, <sup>c</sup> 10-day rolling average)	1 hr minimum sampling time.
5. Fluidized bed units designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen, <sup>c</sup> 30-day rolling average)	1 hr minimum sampling time.
6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen, <sup>c</sup> 30-day rolling average)	1 hr minimum sampling time.
7. Stokers/sloped grate/others designed to burn wet biomass fuel	a. CO (or CEMS)	620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (390 ppm by volume on a dry basis corrected to 3 percent oxygen, <sup>c</sup> 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (2.6E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
8. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel	a. CO	460 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
9. Fluidized bed units designed to burn biomass/bio-based solids	a. CO (or CEMS)	260 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen, <sup>c</sup> 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	9.8E-03 lb per MMBtu of heat input; or (8.3E-05 <sup>a</sup> lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
10. Suspension burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen, <sup>c</sup> 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	470 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen, <sup>c</sup> 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.2E-03 lb per MMBtu of heat input; or (3.9E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
12. Fuel cell units designed to burn biomass/bio-based solids	a. CO	910 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E-02 lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
13. Hybrid suspension grate boiler designed to burn biomass/bio-based solids	a. CO (or CEMS)	1,500 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen, <sup>c</sup> 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.6E-02 lb per MMBtu of heat input; or (4.4E-04 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.



If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
14. Units designed to burn liquid fuel	a. HCl	4.4E-04 lb per MMBtu of heat input	For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	4.8E-07 <sup>a</sup> lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 <sup>b</sup> collect a minimum of 4 dscm.
15. Units designed to burn heavy liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.3E-02 lb per MMBtu of heat input; or (7.5E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
16. Units designed to burn light liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.3E-03 <sup>a</sup> lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
17. Units designed to burn liquid fuel that are non-continental units	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.3E-02 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)	Collect a minimum of 4 dscm per run.
18. Units designed to burn gas 2 (other) gases	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. HCl	1.7E-03 lb per MMBtu of heat input	For M26A, Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E-06 lb per MMBtu of heat input	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 <sup>b</sup> collect a minimum of 3 dscm.
	d. Filterable PM (or TSM)	6.7E-03 lb per MMBtu of heat input; or (2.1E-04 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.

<sup>a</sup> If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to § 63.7515 if all of the other provision of § 63.7515 are met. For all other pollutants that do not contain a footnote "a", your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

<sup>b</sup> Incorporated by reference, see § 63.14.

<sup>c</sup> An owner or operator may determine compliance with the carbon monoxide emissions limit using carbon dioxide as a diluent correction in place of oxygen as described in § 63.7525(a)(1). EPA Method 19 F-factors in 40 CFR part 60, appendix A-7, and EPA Method 19 equations in 40 CFR part 60, appendix A-7, must be used to generate the appropriate CO<sub>2</sub> correction percentage for the fuel type burned in the unit, and must also take into account that the 3% oxygen correction is to be done on a dry basis. The methodology must account for any CO<sub>2</sub> being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc. This methodology must be detailed in the site-specific monitoring plan developed according to § 63.7505(d).

[87 FR 60857, Oct. 6, 2022]

**Table 13 to Subpart DDDDD of Part 63 - Alternative Emission Limits for New or Reconstructed Boilers and Process Heaters That Commenced Construction or Reconstruction After December 23, 2011, and Before April 1, 2013**

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel	a. HCl	0.022 lb per MMBtu of heat input	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
	b. Mercury	8.6E-07 <sup>a</sup> lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 <sup>b</sup> collect a minimum of 4 dscm.
2. Pulverized coal boilers designed to burn coal/solid fossil fuel	a. Carbon monoxide (CO) (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen, <sup>c</sup> 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E-03 lb per MMBtu of heat input; or (2.8E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
3. Stokers designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen, <sup>c</sup> 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.8E-02 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
4. Fluidized bed units designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen, <sup>c</sup> 30-day rolling average)	1 hr minimum sampling time.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
	b. Filterable PM (or TSM)	1.1E-03 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
5. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen, <sup>c</sup> 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E-03 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
6. Stokers/sloped grate/others designed to burn wet biomass fuel	a. CO (or CEMS)	620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (410 ppm by volume on a dry basis corrected to 3 percent oxygen, <sup>c</sup> 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (2.6E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
7. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel	a. CO	460 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.2E-01 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
8. Fluidized bed units designed to burn biomass/bio-based solids	a. CO (or CEMS)	230 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen, <sup>c</sup> 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	9.8E-03 lb per MMBtu of heat input; or (8.3E-05 <sup>a</sup> lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
9. Suspension burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen, <sup>c</sup> 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	5.1E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
10. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	810 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen, <sup>c</sup> 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.6E-02 lb per MMBtu of heat input; or (3.9E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
11. Fuel cell units designed to burn biomass/bio-based solids	a. CO	910 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E-02 lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
12. Hybrid suspension grate boiler designed to burn biomass/bio-based solids	a. CO (or CEMS)	1,500 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen, <sup>c</sup> 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.6E-02 lb per MMBtu of heat input; or (4.4E-04 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
13. Units designed to burn liquid fuel	a. HCl	1.2E-03 lb per MMBtu of heat input	For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	4.9E-07 <sup>a</sup> lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 <sup>b</sup> collect a minimum of 4 dscm.
14. Units designed to burn heavy liquid fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (18 ppm by volume on a dry basis corrected to 3 percent oxygen, <sup>c</sup> 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.3E-03 lb per MMBtu of heat input; or (7.5E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
15. Units designed to burn light liquid fuel	a. CO (or CEMS)	130 <sup>a</sup> ppm by volume on a dry basis corrected to 3 percent oxygen; or (60 ppm by volume on a dry basis corrected to 3 percent oxygen, <sup>c</sup> 1-day block average).	1 hr minimum sampling time.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
	b. Filterable PM (or TSM)	1.1E-03 <sup>a</sup> lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
16. Units designed to burn liquid fuel that are non-continental units	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test; or (91 ppm by volume on a dry basis corrected to 3 percent oxygen, <sup>c</sup> 3-hour rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.3E-02 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
17. Units designed to burn gas 2 (other) gases	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. HCl	1.7E-03 lb per MMBtu of heat input	For M26A, Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E-06 lb per MMBtu of heat input	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 <sup>b</sup> collect a minimum of 3 dscm.
	d. Filterable PM (or TSM)	6.7E-03 lb per MMBtu of heat input; or (2.1E-04 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.

<sup>a</sup> If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit and you are not required to conduct testing for CEMS or CPMS monitor certification, you can skip testing according to § 63.7515 if all of the other provision of § 63.7515 are met. For all other pollutants that do not contain a footnote “a”, your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

<sup>b</sup> Incorporated by reference, see § 63.14.

<sup>c</sup> An owner or operator may determine compliance with the carbon monoxide emissions limit using carbon dioxide as a diluent correction in place of oxygen as described in § 63.7525(a)(1). EPA Method 19 F-factors in 40 CFR part 60, appendix A-7, and EPA Method 19 equations in 40 CFR part 60, appendix A-7, must be used to generate the appropriate CO<sub>2</sub> correction percentage for the fuel type burned in the unit, and must also take into account that the 3% oxygen correction is to be done on a dry basis. The methodology must account for any CO<sub>2</sub> being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc. This methodology must be detailed in the site-specific monitoring plan developed according to § 63.7505(d).

**Table 14 to Subpart DDDDD of Part 63 - Alternative Emission Limits for New or Reconstructed Boilers and Process Heaters <sup>c</sup>**

As stated in § 63.7500, you may continue to comply with the following applicable emission limits until October 6, 2025:

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel.	a. HCl	2.2E-02 lb per MMBtu of heat input	2.5E-02 lb per MMBtu of steam output or 0.28 lb per MWh	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
	b. Mercury	8.0E-07 <sup>a</sup> lb per MMBtu of heat input	8.7E-07 <sup>a</sup> lb per MMBtu of steam output or 1.1E-05 <sup>a</sup> lb per MWh	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 <sup>b</sup> collect a minimum of 4 dscm.
2. Units designed to burn coal/solid fossil fuel	a. Filterable PM (or TSM)	1.1E-03 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)	1.1E-03 lb per MMBtu of steam output or 1.4E-02 lb per MWh; or (2.7E-05 lb per MMBtu of steam output or 2.9E-04 lb per MWh)	Collect a minimum of 3 dscm per run.
3. Pulverized coal boilers designed to burn coal/solid fossil fuel	a. Carbon monoxide (CO) (or CEMS)	130 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3-percent oxygen, <sup>d</sup> 30-day rolling average)	0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
4. Stokers/others designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3-percent oxygen, <sup>d</sup> 30-day rolling average)	0.12 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
5. Fluidized bed units designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3-percent oxygen, <sup>d</sup> 30-day rolling average)	0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3- percent oxygen, <sup>d</sup> 30-day rolling average)	1.2E-01 lb per MMBtu of steam output or 1.5 lb per MWh; 3-run average	1 hr minimum sampling time.
7. Stokers/sloped grate/others designed to burn wet biomass fuel	a. CO (or CEMS)	620 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (390 ppm by volume on a dry basis corrected to 3-percent oxygen, <sup>d</sup> 30-day rolling average)	5.8E-01 lb per MMBtu of steam output or 6.8 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (2.6E-05 lb per MMBtu of heat input)	3.5E-02 lb per MMBtu of steam output or 4.2E-01 lb per MWh; or (2.7E-05 lb per MMBtu of steam output or 3.7E-04 lb per MWh)	Collect a minimum of 2 dscm per run.
8. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel	a. CO	460 ppm by volume on a dry basis corrected to 3-percent oxygen	4.2E-01 lb per MMBtu of steam output or 5.1 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input)	3.5E-02 lb per MMBtu of steam output or 4.2E-01 lb per MWh; or (4.2E-03 lb per MMBtu of steam output or 5.6E-02 lb per MWh)	Collect a minimum of 2 dscm per run.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
9. Fluidized bed units designed to burn biomass/bio-based solids	a. CO (or CEMS)	230 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3-percent oxygen, <sup>d</sup> 30-day rolling average)	2.2E-01 lb per MMBtu of steam output or 2.6 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	9.8E-03 lb per MMBtu of heat input; or (8.3E-05 <sup>a</sup> lb per MMBtu of heat input)	1.2E-02 lb per MMBtu of steam output or 0.14 lb per MWh; or (1.1E-04 <sup>a</sup> lb per MMBtu of steam output or 1.2E-03 <sup>a</sup> lb per MWh)	Collect a minimum of 3 dscm per run.
10. Suspension burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3-percent oxygen, <sup>d</sup> 10-day rolling average)	1.9 lb per MMBtu of steam output or 27 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input)	3.1E-02 lb per MMBtu of steam output or 4.2E-01 lb per MWh; or (6.6E-03 lb per MMBtu of steam output or 9.1E-02 lb per MWh)	Collect a minimum of 2 dscm per run.
11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	330 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3-percent oxygen, <sup>d</sup> 10-day rolling average)	3.5E-01 lb per MMBtu of steam output or 3.6 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.2E-03 lb per MMBtu of heat input; or (3.9E-05 lb per MMBtu of heat input)	4.3E-03 lb per MMBtu of steam output or 4.5E-02 lb per MWh; or (5.2E-05 lb per MMBtu of steam output or 5.5E-04 lb per MWh)	Collect a minimum of 3 dscm per run.
12. Fuel cell units designed to burn biomass/bio-based solids	a. CO	910 ppm by volume on a dry basis corrected to 3-percent oxygen	1.1 lb per MMBtu of steam output or 1.0E+01 lb per MWh	1 hr minimum sampling time.



If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
	b. Filterable PM (or TSM)	2.0E-02 lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	3.0E-02 lb per MMBtu of steam output or 2.8E-01 lb per MWh; or (5.1E-05 lb per MMBtu of steam output or 4.1E-04 lb per MWh)	Collect a minimum of 2 dscm per run.
13. Hybrid suspension grate boiler designed to burn biomass/bio-based solids	a. CO (or CEMS)	1,100 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3-percent oxygen, <sup>d</sup> 30-day rolling average)	1.4 lb per MMBtu of steam output or 12 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.6E-02 lb per MMBtu of heat input; or (4.4E-04 lb per MMBtu of heat input)	3.3E-02 lb per MMBtu of steam output or 3.7E-01 lb per MWh; or (5.5E-04 lb per MMBtu of steam output or 6.2E-03 lb per MWh)	Collect a minimum of 3 dscm per run.
14. Units designed to burn liquid fuel	a. HCl	4.4E-04 lb per MMBtu of heat input	4.8E-04 lb per MMBtu of steam output or 6.1E-03 lb per MWh	For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	4.8E-07 <sup>a</sup> lb per MMBtu of heat input	5.3E-07 <sup>a</sup> lb per MMBtu of steam output or 6.7E-06 <sup>a</sup> lb per MWh	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 <sup>p</sup> collect a minimum of 4 dscm.
15. Units designed to burn heavy liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.3E-02 lb per MMBtu of heat input; or (7.5E-05 <sup>a</sup> lb per MMBtu of heat input)	1.5E-02 lb per MMBtu of steam output or 1.8E-01 lb per MWh; or (8.2E-05 <sup>a</sup> lb per MMBtu of steam output or 1.1E-03 <sup>a</sup> lb per MWh)	Collect a minimum of 3 dscm per run.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
16. Units designed to burn light liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen	0.13 lb per MMBtu of steam output or 1.4 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E-03 <sup>a</sup> lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	1.2E-03 <sup>a</sup> lb per MMBtu of steam output or 1.6E-02 <sup>a</sup> lb per MWh; or (3.2E-05 lb per MMBtu of steam output or 4.0E-04 lb per MWh)	Collect a minimum of 3 dscm per run.
17. Units designed to burn liquid fuel that are non-continental units	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average based on stack test	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.3E-02 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)	2.5E-02 lb per MMBtu of steam output or 3.2E-01 lb per MWh; or (9.4E-04 lb per MMBtu of steam output or 1.2E-02 lb per MWh)	Collect a minimum of 4 dscm per run.
18. Units designed to burn gas 2 (other) gases	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen	0.16 lb per MMBtu of steam output or 1.0 lb per MWh	1 hr minimum sampling time.
	b. HCl	1.7E-03 lb per MMBtu of heat input	2.9E-03 lb per MMBtu of steam output or 1.8E-02 lb per MWh	For M26A, Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E-06 lb per MMBtu of heat input	1.4E-05 lb per MMBtu of steam output or 8.3E-05 lb per MWh	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 <sup>b</sup> collect a minimum of 3 dscm.
	d. Filterable PM (or TSM)	6.7E-03 lb per MMBtu of heat input; or (2.1E-04 lb per MMBtu of heat input)	1.2E-02 lb per MMBtu of steam output or 7.0E-02 lb per MWh; or (3.5E-04 lb per MMBtu of steam output or 2.2E-03 lb per MWh)	Collect a minimum of 3 dscm per run.

<sup>a</sup> If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to § 63.7515 if

all of the other provisions of § 63.7515 are met. For all other pollutants that do not contain a footnote “a”, your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

<sup>b</sup> Incorporated by reference, see § 63.14.

<sup>c</sup> If your affected source is a new or reconstructed affected source that commenced construction or reconstruction after June 4, 2010, and before April 1, 2013, you may comply with the emission limits in Table 11, 12, or 13 to this subpart until January 31, 2016. On and after January 31, 2016, but before October 6, 2025 you may comply with the emission limits in this Table 14. On and after October 6, 2025, you must comply with the emission limits in Table 1 to this subpart.

<sup>d</sup> An owner or operator may determine compliance with the carbon monoxide emissions limit using carbon dioxide as a diluent correction in place of oxygen as described in § 63.7525(a)(1). EPA Method 19 F-factors in 40 CFR part 60, appendix A-7, and EPA Method 19 equations in 40 CFR part 60, appendix A-7, must be used to generate the appropriate CO<sub>2</sub> correction percentage for the fuel type burned in the unit, and must also take into account that the 3% oxygen correction is to be done on a dry basis. The methodology must account for any CO<sub>2</sub> being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc. This methodology must be detailed in the site-specific monitoring plan developed according to § 63.7505(d).

[87 FR 60860, Oct. 6, 2022]

**Table 15 to Subpart DDDDD of Part 63 - Alternative Emission Limits for Existing Boilers and Process Heaters<sup>d</sup>**

As stated in § 63.7500, you may continue to comply with following emission limits until October 6, 2025:

[Units with heat input capacity of 10 million Btu per hour or greater]

<b>If your boiler or process heater is in this subcategory . . .</b>	<b>For the following pollutants . . .</b>	<b>The emissions must not exceed the following emission limits, except during startup and shutdown . . .</b>	<b>The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .</b>	<b>Using this specified sampling volume or test run duration . . .</b>
1. Units in all subcategories designed to burn solid fuel	a. HCl	2.2E-02 lb per MMBtu of heat input	2.5E-02 lb per MMBtu of steam output or 0.27 lb per MWh	For M26A, Collect a minimum of 1 dscm per run; for M26, collect a minimum of 120 liters per run.
	b. Mercury	5.7E-06 lb per MMBtu of heat input	6.4E-06 lb per MMBtu of steam output or 7.3E-05 lb per MWh	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 <sup>b</sup> collect a minimum of 3 dscm.
2. Units design to burn coal/solid fossil fuel	a. Filterable PM (or TSM)	4.0E-02 lb per MMBtu of heat input; or (5.3E-05 lb per MMBtu of heat input)	4.2E-02 lb per MMBtu of steam output or 4.9E-01 lb per MWh; or (5.6E-05 lb per MMBtu of steam output or 6.5E-04 lb per MWh)	Collect a minimum of 2 dscm per run.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
3. Pulverized coal boilers designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3-percent oxygen, <sup>c</sup> 30-day rolling average)	0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
4. Stokers/others designed to burn coal/solid fossil fuel	a. CO (or CEMS)	160 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3-percent oxygen, <sup>c</sup> 30-day rolling average)	0.14 lb per MMBtu of steam output or 1.7 lb per MWh; 3-run average	1 hr minimum sampling time.
5. Fluidized bed units designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3-percent oxygen, <sup>c</sup> 30-day rolling average)	0.12 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3-percent oxygen, <sup>c</sup> 30-day rolling average)	1.3E-01 lb per MMBtu of steam output or 1.5 lb per MWh; 3-run average	1 hr minimum sampling time.
7. Stokers/sloped grate/others designed to burn wet biomass fuel	a. CO (or CEMS)	1,500 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (720 ppm by volume on a dry basis corrected to 3-percent oxygen, <sup>c</sup> 30-day rolling average)	1.4 lb per MMBtu of steam output or 17 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.7E-02 lb per MMBtu of heat input; or (2.4E-04 lb per MMBtu of heat input)	4.3E-02 lb per MMBtu of steam output or 5.2E-01 lb per MWh; or (2.8E-04 lb per MMBtu of steam output or 3.4E-04 lb per MWh)	Collect a minimum of 2 dscm per run.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
8. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel	a. CO	460 ppm by volume on a dry basis corrected to 3-percent oxygen	4.2E-01 lb per MMBtu of steam output or 5.1 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.2E-01 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input)	3.7E-01 lb per MMBtu of steam output or 4.5 lb per MWh; or (4.6E-03 lb per MMBtu of steam output or 5.6E-02 lb per MWh)	Collect a minimum of 1 dscm per run.
9. Fluidized bed units designed to burn biomass/bio-based solid	a. CO (or CEMS)	470 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3-percent oxygen, <sup>c</sup> 30-day rolling average)	4.6E-01 lb per MMBtu of steam output or 5.2 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E-01 lb per MMBtu of heat input; or (1.2E-03 lb per MMBtu of heat input)	1.4E-01 lb per MMBtu of steam output or 1.6 lb per MWh; or (1.5E-03 lb per MMBtu of steam output or 1.7E-02 lb per MWh)	Collect a minimum of 1 dscm per run.
10. Suspension burners designed to burn biomass/bio-based solid	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3-percent oxygen, <sup>c</sup> 10-day rolling average)	1.9 lb per MMBtu of steam output or 27 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	5.1E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input)	5.2E-02 lb per MMBtu of steam output or 7.1E-01 lb per MWh; or (6.6E-03 lb per MMBtu of steam output or 9.1E-02 lb per MWh)	Collect a minimum of 2 dscm per run.
11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solid	a. CO (or CEMS)	770 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3-percent oxygen, <sup>c</sup> 10-day rolling average)	8.4E-01 lb per MMBtu of steam output or 8.4 lb per MWh; 3-run average	1 hr minimum sampling time.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
	b. Filterable PM (or TSM)	2.8E-01 lb per MMBtu of heat input; or (2.0E-03 lb per MMBtu of heat input)	3.9E-01 lb per MMBtu of steam output or 3.9 lb per MWh; or (2.8E-03 lb per MMBtu of steam output or 2.8E-02 lb per MWh)	Collect a minimum of 1 dscm per run.
12. Fuel cell units designed to burn biomass/bio-based solid	a. CO	1,100 ppm by volume on a dry basis corrected to 3-percent oxygen	2.4 lb per MMBtu of steam output or 12 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E-02 lb per MMBtu of heat input; or (5.8E-03 lb per MMBtu of heat input)	5.5E-02 lb per MMBtu of steam output or 2.8E-01 lb per MWh; or (1.6E-02 lb per MMBtu of steam output or 8.1E-02 lb per MWh)	Collect a minimum of 2 dscm per run.
13. Hybrid suspension grate units designed to burn biomass/bio-based solid	a. CO (or CEMS)	3,500 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3-percent oxygen, <sup>c</sup> 30-day rolling average)	3.5 lb per MMBtu of steam output or 39 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	4.4E-01 lb per MMBtu of heat input; or (4.5E-04 lb per MMBtu of heat input)	5.5E-01 lb per MMBtu of steam output or 6.2 lb per MWh; or (5.7E-04 lb per MMBtu of steam output or 6.3E-03 lb per MWh)	Collect a minimum of 1 dscm per run.
14. Units designed to burn liquid fuel	a. HCl	1.1E-03 lb per MMBtu of heat input	1.4E-03 lb per MMBtu of steam output or 1.6E-02 lb per MWh	For M26A, collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	2.0E-06 lb per MMBtu of heat input	2.5E-06 lb per MMBtu of steam output or 2.8E-05 lb per MWh	For M29, collect a minimum of 3 dscm per run; for M30A or M30B collect a minimum sample as specified in the method, for ASTM D6784 <sup>b</sup> collect a minimum of 2 dscm.
15. Units designed to burn heavy liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
	b. Filterable PM (or TSM)	6.2E-02 lb per MMBtu of heat input; or (2.0E-04 lb per MMBtu of heat input)	7.5E-02 lb per MMBtu of steam output or 8.6E-01 lb per MWh; or (2.5E-04 lb per MMBtu of steam output or 2.8E-03 lb per MWh)	Collect a minimum of 1 dscm per run.
16. Units designed to burn light liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen	0.13 lb per MMBtu of steam output or 1.4 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	7.9E-03 lb per MMBtu of heat input; or (6.2E-05 lb per MMBtu of heat input)	9.6E-03 lb per MMBtu of steam output or 1.1E-01 lb per MWh; or (7.5E-05 lb per MMBtu of steam output or 8.6E-04 lb per MWh)	Collect a minimum of 3 dscm per run.
17. Units designed to burn liquid fuel that are non-continental units	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average based on stack test	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.7E-01 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)	3.3E-01 lb per MMBtu of steam output or 3.8 lb per MWh; or (1.1E-03 lb per MMBtu of steam output or 1.2E-02 lb per MWh)	Collect a minimum of 2 dscm per run.
18. Units designed to burn gas 2 (other) gases	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen	0.16 lb per MMBtu of steam output or 1.0 lb per MWh	1 hr minimum sampling time.
	b. HCl	1.7E-03 lb per MMBtu of heat input	2.9E-03 lb per MMBtu of steam output or 1.8E-02 lb per MWh	For M26A, collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E-06 lb per MMBtu of heat input	1.4E-05 lb per MMBtu of steam output or 8.3E-05 lb per MWh	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 <sup>b</sup> collect a minimum of 2 dscm.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
	d. Filterable PM (or TSM)	6.7E-03 lb per MMBtu of heat input or (2.1E-04 lb per MMBtu of heat input)	1.2E-02 lb per MMBtu of steam output or 7.0E-02 lb per MWh; or (3.5E-04 lb per MMBtu of steam output or 2.2E-03 lb per MWh)	Collect a minimum of three dscm per run.

<sup>a</sup> If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to § 63.7515 if all of the other provisions of § 63.7515 are met. For all other pollutants that do not contain a footnote a, your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

<sup>b</sup> Incorporated by reference, see § 63.14.

<sup>c</sup> An owner or operator may determine compliance with the carbon monoxide emissions limit using carbon dioxide as a diluent correction in place of oxygen as described in § 63.7525(a)(1). EPA Method 19 F-factors in 40 CFR part 60, appendix A-7, and EPA Method 19 equations in 40 CFR part 60, appendix A-7, must be used to generate the appropriate CO<sub>2</sub> correction percentage for the fuel type burned in the unit, and must also take into account that the 3% oxygen correction is to be done on a dry basis. The methodology must account for any CO<sub>2</sub> being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc. This methodology must be detailed in the site-specific monitoring plan developed according to § 63.7505(d).

<sup>d</sup> Before October 6, 2025 you may comply with the emission limits in this Table 15. On and after October 6, 2025, you must comply with the emission limits in Table 2 to this subpart.

[87 FR 60863, Oct. 6, 2022]



Indiana Department of Environmental Management  
Office of Air Quality

Technical Support Document (TSD) for a Part 70 Operating Permit  
Renewal

**Source Description and Location**

<b>Source Name:</b>	<b>Duke Energy Indiana, LLC - Cayuga Generating Station</b>
<b>Source Location:</b>	<b>3300 N SR 63, Cayuga, Indiana 47928</b>
<b>County:</b>	<b>Vermillion</b>
<b>SIC Code:</b>	<b>4911 (Electric Services)</b>
<b>Permit Renewal No.:</b>	<b>T 165-47094-00001</b>
<b>Permit Reviewer:</b>	<b>Christopher Chin</b>

On September 29, 2023, Duke Energy Indiana, LLC - Cayuga generating Station submitted an application to the Office of Air Quality (OAQ) requesting to renew its operating permit. OAQ has reviewed the operating permit renewal application from Duke Energy Indiana, LLC - Cayuga generating Station relating to the operation of a stationary electric utility generating station. Duke Energy Indiana, LLC - Cayuga generating Station was issued its third Part 70 Operating Permit Renewal (T165-40249-00001) on July 29, 2019.

**Source Definition**

This source consists of a power plant and a combustion turbine plant:

- (a) Duke Energy Indiana, LLC - Cayuga Generating Station (ID # 165-00001), a power plant, is located at, 3300 N SR 63, Cayuga, IN 47928; and
- (b) Duke Energy Indiana, LLC - Cayuga Generating Station Unit 4 combustion turbine plant (ID # 165-00086), is located at 3300 N SR 63, Cayuga, IN 47928.

IDEM, OAQ has examined whether the Cayuga Generating Station plant and the combustion turbine plant are part of the same major source.

IDEM, OAQ finds that the two plants are part of the same major source.

This determination was initially made under first Part 70 Operating Permit Renewal No. T165-27260-00001. IDEM, OAQ will issue separate Part 70 permits to each plant solely for administrative purposes.

**Existing Approvals**

The source was issued Part 70 Operating Permit Renewal No. T165-40249-00001 on July 29, 2019. The source has since received the following approval:

TV Significant Permit Modification No. 165-41842-00001 on May 29, 2020.

All terms and conditions of previous permits issued pursuant to permitting programs approved into the State Implementation Plan have been either incorporated as originally stated, revised, or deleted by this permit. All previous registrations and permits are superseded by this permit.

**Emission Units and Pollution Control Equipment**

The source consists of the following permitted emission units:

- (a) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 1, installed in 1967, using #2 fuel oil for startup, shutdown, and stabilization purposes, with a nominal heat input capacity of 4,802 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, a flue gas desulfurization (FGD) system for control of SO<sub>2</sub>, and exhausting to stack 1. Stack 1 has continuous emissions monitors (CEMs) for nitrogen oxides (NO<sub>x</sub>), sulfur dioxide (SO<sub>2</sub>), and particulate matter (PM). Boiler No. 1 was configured with a low NO<sub>x</sub> burner in 1993. Selective Catalytic Oxidation (SCR) to control NO<sub>x</sub>, Dry Sorbent Injection System to Control SO<sub>3</sub>, Activated Carbon Injection System to assist in Control of Hg emissions constructed in 2015. The Boiler is equipped with a PM CEMs, SO<sub>2</sub> CEMs, and NO<sub>x</sub> CEMs, and HG CEMs

[Under NESHAP Subpart UUUUU, this unit is part of an affected source.]

- (b) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 2, installed in 1968, using #2 fuel oil for startup, shutdown, and stabilization purposes, with a nominal heat input capacity of 4,802 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, a flue gas desulfurization (FGD) system for control of SO<sub>2</sub>, and exhausting to stack 2. Stack 2 has continuous emissions monitors (CEMs) for nitrogen oxides (NO<sub>x</sub>), sulfur dioxide (SO<sub>2</sub>), and particulate matter (PM). Boiler No. 2 was configured with a low NO<sub>x</sub> burner in 1993. Selective Catalytic Oxidation (SCR) to control NO<sub>x</sub>, Dry Sorbent Injection System to Control SO<sub>3</sub>, Activated Carbon Injection System to assist in Control of Hg emissions constructed in 2015. The Boiler is equipped with a PM CEMs, SO<sub>2</sub> CEMs, NO<sub>x</sub> CEMs, and Hg CEMs.

[Under NESHAP Subpart UUUUU, this unit is part of an affected source.]

- (c) One (1) no. 2 fuel oil-fired generator, identified as Unit No. 3A, installed in 1972, with a nominal heat input capacity of 30 million Btu per hour (MMBtu/hr), using an oxidation catalyst installed in 2017 as control, and exhausting to stack 3A.

[This is an affected facility under 40 CFR 63, Subpart ZZZZ]

- (d) One (1) no. 2 fuel oil-fired generator, identified as Unit No. 3B, installed in 1972, with a nominal heat input capacity of 30 million Btu per hour (MMBtu/hr), using an oxidation catalyst installed in 2017 as control, and exhausting to stack 3B.

[This is an affected facility under 40 CFR 63, Subpart ZZZZ]

- (e) One (1) no. 2 fuel oil-fired generator, identified as Unit No. 3C, installed in 1972, with a nominal heat input capacity of 30 million Btu per hour (MMBtu/hr), using an oxidation catalyst installed in 2017 as control, and exhausting to stack 3C.

[This is an affected unit under 40 CFR 63, Subpart ZZZZ]

- (f) One (1) no. 2 fuel oil-fired generator, identified as Unit No. 3D, installed in, with a nominal heat input capacity of 30 million Btu per hour (MMBtu/hr), using an oxidation catalyst installed in 2017 as control, and exhausting to stack 3D.

[This is an affected unit under 40 CFR 63, Subpart ZZZZ]

- (g) A dual conveyor coal processing system, constructed in 1967/1968, with a nominal throughput of 1900 tons of coal per hour (950 tons of coal per hour each side), consisting of the following equipment:

- (1) One (1) railcar unloading station with a drop point to two (2) hoppers, with a capacity of 1900 tons, identified as DP-1, with the drop point enclosed with emissions uncontrolled, and exhausting to the ambient air.
- (2) One (1) storage area having a nominal storage capacity including the active piles of 982,800 tons, with fugitive emissions controlled as needed by a watering truck.

- (3) One (1) enclosed hopper, with a drop point to a conveyor identified as DP-2, with a capacity of 1900 tons with the drop point enclosed and exhausting to the ambient air.
  - (4) One (1) enclosed hopper and two (2) reclaim feeders, with a capacity of 1900 tons with underground drop points identified as DP-11 and DP-12, with emissions controlled by the underground enclosure, and routed to the conveyor system.
  - (5) An enclosed dual conveyor system, with 6 drop points identified as DP-3 through DP-6, DP-8, and DP-13, with a capacity of 1900 tons with each drop point enclosed with emissions controlled by the enclosure.
  - (6) An enclosed conveyor system with drop point identified as DP-9, with a capacity of 1900 tons controlled by a telescoping chute.
  - (7) Coal bunker, with a capacity of 1900 tons controlled by a rotoclone.
- (h) One (1) limestone handling and storage system for the flue gas desulfurization system, constructed in 2006, with a maximum throughput rate of 1,000 tons per hour, consisting of the following:
- (1) One (1) railcar/truck unloading operation with a maximum capacity of 1,000 tons per hour, controlled by fog dust suppression, and exhausting to emission point EP-L1.
  - (2) Two (2) hoppers, each with a maximum capacity of 500 tons per hour controlled by fog dust suppression, and exhausting to emission point EP-L2.
  - (3) Two (2) belt feeders, identified as LHBF-1 and LHBF-2 each with a maximum capacity of 500 tons per hour, controlled by fog dust suppression, and exhausting to emission point EP-L2.
  - (4) One (1) conveyor, identified as LH-1 controlled by a telescopic chute, and exhausting to emission point EP-L3. Under NSPS, Subpart OOO, this unit is considered a belt conveyor.
  - (5) One (1) active limestone stockout pile with a maximum capacity of 7,700 tons.
  - (6) One (1) inactive limestone storage pile with a maximum capacity of 45,000 tons.
  - (7) Two (2) reclaim hoppers each with a maximum capacity of 200 tons per hour, controlled by fog dust suppression, and exhausting to emission point EP-L4.
  - (8) Two (2) belt feeders, identified as LHBF-3 and LHBF-4 each with a maximum capacity of 200 tons per hour, controlled by fog dust suppression, and exhausting to emission point EP-L4.
  - (9) One (1) conveyor, identified as LH-2 with a maximum capacity of 400 tons per hour, controlled by fog dust suppression. The emissions exhaust out the general building vents, identified as emission point EP-L18a and EP-L18b. Under NSPS, Subpart OOO, this unit is considered a belt conveyor.
  - (10) One (1) reversible conveyor, identified as LH-3 with a maximum capacity of 400 tons per hour, controlled by fog dust suppression. The emissions exhaust out the general building vents, identified as emission points EP-L18a and EP-L18b. Under NSPS, Subpart OOO, this unit is considered a belt conveyor.
  - (11) Two (2) day bins each with a maximum throughput rate of 400 tons per hour. Each bin is equipped with a filter to control particulate emissions. Filter F-L1 and F-L2 exhaust to EP-

L16 and EP-L17, respectively. Under NSPS, Subpart OOO, these units are considered storage bins.

- (12) Two (2) wet ball mills each with a maximum capacity of 51 tons of limestone slurry per hour. Under NSPS, Subpart OOO, these units are considered grinding mills.
- (i) One (1) gypsum handling and storage system, constructed in 2006, consisting of the following:
- (1) One (1) wet gypsum conveying system with a maximum throughput rate of 150 tons per hour.
- (2) Two (2) gypsum stock out piles Gypsum can be stocked out to an outside pile or a pile located in the gypsum stock out building. The maximum gypsum storage capacity is 10,400 tons.
- (3) One (1) emergency gypsum stockout pile with a maximum capacity of 2,600 tons.
- (4) One (1) dry gypsum transferring operation transferring gypsum to landfills by trucks on paved roads.
- (j) One (1) Auxiliary Boiler, identified as emission unit Aux, with a maximum heat input capacity of 72.76 MMBtu/hr fired with distillate oil and exhausting out one stack identified as stack Aux-1. The Auxiliary boiler was constructed before 1968.
- [Under NESHAP 40 CFR 63, Subpart DDDDD, this unit is part of an affected source]
- (k) One (1) Arsenic Mitigation System consisting of (1) 700 ton Limestone Storage Silo and (1) 300 ton Limestone Surge Bin, constructed in 2015. Limestone is pneumatically conveyed from delivery trucks to the Limestone Storage Silo and from the Limestone Storage Silo to the Limestone Surge Bin. Limestone in the Surge Bin is dropped on to the C-1 and C-2 coal conveyors. PM emissions generated during pneumatic conveying and transfer points to the C-1 and C-2 conveyor will be controlled by the bin vent filters. The Limestone Storage Silo and Limestone Surge Bin are identified as emissions points EP-01(LS) and EP-02(LS).
- (l) Two (2) Dry Sorbent Injection (DSI) Systems, one for each Unit. Each DSI system consists of one (1) Sorbent Storage Silo with a storage capacity of 120 tons, three (3) Silo Weight Feeders to regulate sorbent from the silos and a system to inject the sorbent material into the flue gas, constructed 2015. PM emissions generated during loading operations are controlled by a Bin Vent Filter located on the top of each silo and the weight feeders. The two (2) Sorbent Silos are identified as emission points EP-01(DSI), and EP-03(DSI). The weight feeders are identified as EP-05A(DSI), EP-05B(DSI), EP-06A(DSI) and EP-06B(DSI) with spares EP-05C(DSI) and EP-06C(DSI).
- (m) Two (2) Dry Ash Handling Systems, one for each Unit. The dry ash handling system consists of a pneumatic conveying system, four (4) baghouse separators, one (1) ash silo with a storage capacity of 3,500 and an ash unloading system, constructed in 2015.
- (i) Baghouse Separators - Fly ash from the ESP Ash Hoppers, Air Heater Ash Hoppers, Economizer Ash Hoppers and SCR Large Particle Screen. Ash Hopper will be pneumatically conveyed to one of four (4) baghouse separators. There will be two (2) baghouse separators for each unit. The dry fly ash is separated from the air stream in a baghouse separator. Each baghouse separator is identified as emissions points EP-01(DFA), EP-02(DFA), EP-03(DFA), and EP-04(DFA). The system is equipped with a spare exhauster identified as emissions point EP-05(DFA).
- (ii) Ash Silos - Fly ash collected in the baghouse separators is dropped into a feeder and pneumatically conveyed to the ash silo. The ash silo is equipped with a bin vent filter to

control particulate matter emissions from pneumatic conveying. The Ash Silo is identified as emission point EP-06(DFA).

- (iii) Ash Unloading Operation - Fly ash collected in the silos can be unloaded into trucks or pneumatically conveyed to the ash fixation process. Fly ash unloaded into trucks can be unloaded dry or wet. Fly ash unloaded dry is gravity feed to a chute and unloaded into enclosed trucks for beneficial reuse offsite. The emissions generated from unloading the ash dry are vented back to the silo and controlled by the silo bin vent filter. Ash unloaded wet is fed into a pin mixer where the ash is mixed with water and unloaded into open trucks for disposal in the onsite landfill.
- (n) One (1) Ash Fixation Process consisting of a pneumatic conveying system, one (1) lime silo, conveyors, and two (2) pin mixers.
  - (i) Lime Silo – Lime will be delivered by truck and will be pneumatically loaded into the silo. The storage capacity of the silo is 300 tons, constructed in 2015. The emissions generated by the pneumatic conveying will be controlled by a bin vent filter located on top of the lime silo. The Lime Silo is identified as emissions point EP-02(FIX).
  - (ii) Conveyor and Transfer Points – Fly ash, Lime and Gypsum will be conveyed to one of two (2) pin mixers where this material will be mixed with water to make the fixated ash constructed in 2015. The fixated ash will be unloaded to a storage pile, loaded into trucks using front end loaders and hauled to the landfill.

<b>Insignificant Activities</b>
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The source also consists of the following insignificant activities:

- (a) Degreasing operations that do not exceed one hundred forty-five (145) gallons per twelve months, except if subject to 326 IAC 20-6. [326 IAC 8-3-2] [326 IAC 8-3-8]
- (b) One (1) Diesel Fired Emergency Generator, identified as ENG-01 with maximum capacity of 156.9 HP (100 kW), CI ICE with a displacement 4.4 liters, Manufactured by Caterpillar Model Year 2007, Model D100-6, constructed in 2007, exhausting outside the building. This generator is located in the switch yard and is operated as backup for the black start diesel aux feed.  
  
[This is an affected facility under 40 CFR 60, Subpart IIII]  
[This is an affected unit under 40 CFR 63, Subpart ZZZZ]
- (c) One (1) Diesel Fired Emergency Engine, identified as ENG-02, with maximum capacity of 713 Hp (450 kW), CI ICE with a displacement 15.2 liters, Manufactured by Caterpillar, Model Year 2007, Model C15DITA, constructed in 2007, exhausting outside the building. This engine is used to quench the fuel gas if the scrubber should fail.  
  
[This is an affected facility under 40 CFR 60, Subpart IIII]  
[This is an affected unit under 40 CFR 63, Subpart ZZZZ]
- (d) One (1) Emergency Diesel Fire Pump Engine, identified as ENG-03, with maximum capacity of 430 Hp (321 kW) CI, manufactured by Caterpillar, Model Year 2005, Model 3406, exhausting outside the building.  
  
[This is an affected unit under 40 CFR 63, Subpart ZZZZ]
- (e) One (1) SI emergency engine, identified as ENG-04 with maximum capacity of 67 Hp (50 kW), manufactured by Power Solutions International, fired with LPG, model year 2018 exhausting outside the building. The engine is used provide backup power to a microwave tower during the loss of power.

[This is an affected facility under 40 CFR 60, Subpart JJJJ]  
 [This is an affected unit under 40 CFR 63, Subpart ZZZZ]

**Emission Units and Pollution Control Equipment  
 Constructed Under the Provisions of 326 IAC 2-1.1-3 (Exemptions)**

As part of this permitting action, the source requested to add the following existing emission unit(s) constructed under the provisions of 326 IAC 2-1.1-3 (Exemptions):

- (a) One (1) SI propane emergency generator, identified as ENG-05, permitted in 2024, with a maximum capacity of 229 brake horsepower, using no controls, and exhausting to atmosphere.

[This is an affected facility under 40 CFR 60, Subpart JJJJ]  
 [[This is an affected unit under 40 CFR 63, Subpart ZZZZ]

The total potential to emit of the emission unit(s) is less than levels specified at 326 IAC 2-1.1-3(e)(1)(A) through (G) and the addition of the emission unit(s) did not require the source to transition to a higher operation permit level. Therefore, pursuant to 326 IAC 2-1.1-3(e), the modification approval requirements under 326 IAC 2-7-10.5, including the requirement to submit an application, do not apply to the emission unit(s). See Appendix A of this Technical Support Document for detailed emission calculations.

**Enforcement Issue**

There are no enforcement actions pending.

**Emission Calculations**

See Appendix A of this Technical Support Document for detailed emission calculations.

**County Attainment Status**

The source is located in Vermillion County.

Pursuant to amendments to Indiana Code IC 13-17-3-14, effective July 1, 2023, a federal regulation that classifies or amends a designation of attainment, nonattainment, or unclassifiable for any area in Indiana under the federal Clean Air Act is effective and enforceable in Indiana on the effective date of the federal regulation.

Pollutant	Designation
SO <sub>2</sub>	Unclassifiable or attainment effective April 9, 2018, for the 2010 primary 1-hour SO <sub>2</sub> standard. Better than national secondary standards effective March 3, 1978.
CO	Unclassifiable or attainment effective November 15, 1990.
O <sub>3</sub>	Unclassifiable or attainment effective January 16, 2018, for the 2015 8-hour ozone standard.
PM <sub>2.5</sub>	Unclassifiable or attainment effective April 15, 2015, for the 2012 annual PM <sub>2.5</sub> standard.
PM <sub>2.5</sub>	Unclassifiable or attainment effective December 13, 2009, for the 2006 24-hour PM <sub>2.5</sub> standard.
PM <sub>10</sub>	Attainment effective October 27, 1997, for the part of Clinton Township that includes sections 15, 16, 21, 22, 27, 28, 33, and 34. Unclassifiable effective November 15, 1990, for the remainder of Vermillion County.
NO <sub>2</sub>	Unclassifiable or attainment effective January 29, 2012, for the 2010 NO <sub>2</sub> standard.
Pb	Unclassifiable or attainment effective December 31, 2011, for the 2008 lead standard.

- (a) Ozone Standards  
 Volatile organic compounds (VOC) and Nitrogen Oxides (NO<sub>x</sub>) are regulated under the Clean Air Act (CAA) for the purposes of attaining and maintaining the National Ambient Air Quality

Standards (NAAQS) for ozone. Therefore, VOC and NO<sub>x</sub> emissions are considered when evaluating the rule applicability relating to ozone. Vermillion County has been designated as attainment or unclassifiable for ozone. Therefore, VOC and NO<sub>x</sub> emissions were reviewed pursuant to the requirements of Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

- (b) PM<sub>2.5</sub>  
Vermillion County has been classified as attainment for PM<sub>2.5</sub>. Therefore, direct PM<sub>2.5</sub>, SO<sub>2</sub>, and NO<sub>x</sub> emissions were reviewed pursuant to the requirements of Prevention of Significant Deterioration (PSD), 326 IAC 2-2.
- (c) Other Criteria Pollutants  
Vermillion County has been classified as attainment or unclassifiable in Indiana for all the other criteria pollutants. Therefore, these emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

### Fugitive Emissions

Since this source is classified as a fossil fuel fired steam electric plant of more than two hundred fifty million (250,000,000) British thermal units per hour input, it is considered one (1) of the twenty-eight (28) listed source categories, as specified in 326 IAC 2-2-1(ff)(1), 326 IAC 2-3-2(g), or 326 IAC 2-7-1(22)(B). Therefore, fugitive emissions are counted toward the determination of PSD, Emission Offset, and Part 70 Permit applicability.

The fugitive emissions of hazardous air pollutants (HAP) are counted toward the determination of Part 70 Permit applicability and source status under Section 112 of the Clean Air Act (CAA).

### Greenhouse Gas (GHG) Emissions

On June 23, 2014, in the case of *Utility Air Regulatory Group v. EPA*, cause no. 12-1146, (available at [http://www.supremecourt.gov/opinions/13pdf/12-1146\\_4g18.pdf](http://www.supremecourt.gov/opinions/13pdf/12-1146_4g18.pdf)) the United States Supreme Court ruled that the U.S. EPA does not have the authority to treat greenhouse gases (GHGs) as an air pollutant for the purpose of determining operating permit applicability or PSD Major source status. On July 24, 2014, the U.S. EPA issued a memorandum to the Regional Administrators outlining next steps in permitting decisions in light of the Supreme Court's decision. U.S. EPA's guidance states that U.S. EPA will no longer require PSD or Title V permits for sources "previously classified as 'Major' based solely on greenhouse gas emissions."

The Indiana Environmental Rules Board adopted the GHG regulations required by U.S. EPA at 326 IAC 2-2-1(zz), pursuant to Ind. Code § 13-14-9-8(h) (Section 8 rulemaking). A rule, or part of a rule, adopted under Section 8 is automatically invalidated when the corresponding federal rule, or part of the rule, is invalidated. Due to the United States Supreme Court Ruling, IDEM, OAQ cannot consider GHG emissions to determine operating permit applicability or PSD applicability to a source or modification.

**Unrestricted Potential Emissions**

This table reflects the unrestricted potential emissions of the source.

	Unrestricted Potential Emissions (ton/year)								
	PM <sup>1</sup>	PM <sub>10</sub> <sup>1</sup>	PM <sub>2.5</sub> <sup>1,2</sup>	SO <sub>2</sub>	NO <sub>x</sub>	VOC	CO	Single HAP <sup>3</sup>	Total HAPs
<b>Total PTE of Entire Source Including Fugitives Cayuga Generating Station*</b>	158,802	49,604	22,707	247,671	31,358	167	1,489	>10	>25
<b>Total PTE of Entire Source Including Fugitives Unit 4*</b>	68.26	24.45	40.91	4,999.2	4,999.2	11.93	465.83	4.04	5.55
<b>Total PTE of Entire Source Including Fugitives*</b>	158,870	49,628	22,748	252,827	36,357	179	1,955	>10	>25
Title V Major Source Thresholds	NA	100	100	100	100	100	100	10	25
PSD Major Source Thresholds	100	100	100	100	100	100	100	--	--

<sup>1</sup>Under the Part 70 Permit program (40 CFR 70), PM<sub>10</sub> and PM<sub>2.5</sub>, not particulate matter (PM), are each considered as a "regulated air pollutant."  
<sup>2</sup>PM<sub>2.5</sub> listed is direct PM<sub>2.5</sub>.  
<sup>3</sup>Single highest source-wide HAP  
 \*Fugitive HAP emissions are always included in the source-wide emissions.

Appendix A of this TSD reflects the detailed unrestricted potential emissions of the source.

- (a) The potential to emit (as defined in 326 IAC 2-7-1(30)) of PM<sub>10</sub>, PM 2.5, SO<sub>2</sub>, NO<sub>x</sub>, VOC, and CO are equal to or greater than one hundred (100) tons per year. Therefore, the source is subject to the provisions of 326 IAC 2-7 and will be issued a Part 70 Operating Permit Renewal.
- (b) The potential to emit (as defined in 326 IAC 2-7-1(30)) of any single HAP is equal to or greater than ten (10) tons per year and/or the potential to emit (as defined in 326 IAC 2-7-1(30)) of a combination of HAPs is equal to or greater than twenty-five (25) tons per year. The source will be issued a Part 70 Operating Permit Renewal.

**Actual Emissions**

The following table shows the actual emissions as reported by the source. This information reflects the 2022 OAQ emission data.

Actual Emissions (tons/year)							
PM <sub>10</sub>	PM <sub>2.5</sub>	SO <sub>2</sub>	NO <sub>x</sub>	VOC	CO	Lead (Pb)*	Ammonia (NH <sub>3</sub> )
110	73	1667.8	4305	63	522	-	-

\*Lead and lead compounds, including any unique chemical substance that contains lead.

**Part 70 Permit Conditions**

This source is subject to the requirements of 326 IAC 2-7, because the source met the following:

- (a) Emission limitations and standards, including those operational requirements and limitations that assure compliance with all applicable requirements at the time of issuance of Part 70 permits.



- (b) Monitoring and related record keeping requirements which assume that all reasonable information is provided to evaluate continuous compliance with the applicable requirements.

**Potential to Emit After Issuance**

The table below summarizes the potential to emit, reflecting all limits, of the emission units. Any new control equipment is considered federally enforceable only after issuance of this Part 70 permit renewal, and only to the extent that the effect of the control equipment is made practically enforceable in the permit.

	Potential To Emit of the Entire Source After Issuance of Renewal (tons/year)								
	PM <sup>1</sup>	PM <sub>10</sub> <sup>1</sup>	PM <sub>2.5</sub> <sup>1,2</sup>	SO <sub>2</sub>	NO <sub>x</sub>	VOC	CO	Single HAP <sup>3</sup>	Total HAPs
<b>Total PTE of Entire Source Including Fugitives Cayuga Generating Station*</b>	1,338.43	2,153.26	2141.30	9,168.79	20,622	132.98	1125.50	>10	>25
<b>Total PTE of Entire Source Including Fugitives Unit 4*</b>	68.26	24.45	40.91	187.47	4,999.16	11.93	465.83	4.04	5.55
<b>Total PTE of Entire Source Including Fugitives*</b>	1,406.7	2,177.7	2,182.2	9,372.0	25,621.6	144.9	1,591.3	>10	>25
Title V Major Source Thresholds	NA	100	100	100	100	100	100	10	25
PSD Major Source Thresholds	100	100	100	100	100	100	100	NA	NA

<sup>1</sup>Under the Part 70 Permit program (40 CFR 70), PM<sub>10</sub> and PM<sub>2.5</sub>, not particulate matter (PM), are each considered as a "regulated air pollutant."

<sup>2</sup>PM<sub>2.5</sub> listed is direct PM<sub>2.5</sub>.

<sup>3</sup>Single highest source-wide HAP.

\*Fugitive HAP emissions are always included in the source-wide emissions.

Appendix A of this TSD reflects the detailed potential to emit of the entire source after issuance.

- (a) This existing source is a major stationary source, under PSD (326 IAC 2-2), because the PSD regulated pollutants, PM, PM<sub>10</sub>, PM<sub>2.5</sub>, SO<sub>2</sub>, NO<sub>x</sub>, VOC, and CO are emitted at a rate of 100 tons per year or more, and it is one of the twenty-eight (28) listed source categories, as specified in 326 IAC 2-2-1(ff)(1).
- (b) This source is a major source of HAP, as defined in 40 CFR 63.2, because HAP emissions are equal to or greater than ten (10) tons per year for a single HAP and equal to or greater than twenty-five (25) tons per year for a combination of HAPs. Therefore, this source is a major source under Section 112 of the Clean Air Act (CAA).

**Federal Rule Applicability**

Federal rule applicability for this source has been reviewed as follows:

**New Source Performance Standards (NSPS):**

- (a) The requirements of the New Source Performance Standard for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971, 40 CFR 60, Subpart D and 326 IAC 12, are not included in the permit for Boiler No. 1, Boiler No. 2 and Auxiliary Boiler

because construction on these boilers commenced prior to August 17, 1971, as determined by the United States District Court for the Southern District of Indiana in the case of United States of America v. Public Service Company of Indiana, Inc. on September 30, 1977.

- (b) The requirements of the New Source Performance Standard for Coal Preparation and Processing Plants, 40 CFR 60, Subpart Y and 326 IAC 12, are not included in the permit for the coal processing and conveying equipment, storage systems, and transfer and loading systems because all of these emission units were constructed before October 24, 1974, and have not been modified after that date, thus this subpart does not apply.
- (c) The one (1) limestone handling and storage system for the flue gas desulfurization system are subject to the requirements of the New Source Performance Standard, 40 CFR 60, Subpart OOO, Standards of Performance for Nonmetallic Mineral Processing Plants, because the proposed project involves crushing of limestone which is considered a nonmetallic mineral as defined in 40 CFR 60.671. The specific facility subject to this rule includes the following:
  - (1) One (1) limestone handling and storage system for the flue gas desulfurization system, constructed in 2006, with a maximum throughput rate of 1,000 tons per hour, consisting of the following:
    - (A) One (1) conveyor, identified as LH-1, controlled by a telescopic chute, and exhausting to emission point EP-L3. Under NSPS, Subpart OOO, this unit is considered a belt conveyor.
    - (B) One (1) conveyor, identified as LH-2, with a maximum capacity of 400 tons per hour, controlled by fog dust suppression. The emissions exhaust out the general building vents, identified as emission point EP-L18a and EP-L18b. Under NSPS, Subpart OOO, this unit is considered a belt conveyor.
    - (C) One (1) reversible conveyor, identified as LH-3, with a maximum capacity of 400 tons per hour, controlled by fog dust suppression. The emissions exhaust out the general building vents, identified as emission points EP-L18a and EP-L18b. Under NSPS, Subpart OOO, this unit is considered a belt conveyor.
    - (D) Two (2) day bins, each with a maximum throughput rate of 400 tons per hour. Each bin is equipped with a Baghouse to control particulate emissions. Baghouses BH-L1 and BH-L2 exhaust to EP-L16 and EP-L17, respectively. Under NSPS, Subpart OOO, these units are considered storage bins.
    - (E) Two (2) wet ball mills, each with a maximum capacity of 51 tons of limestone slurry per hour. Under NSPS, Subpart OOO, these units are considered grinding mills.

These emission units are subject to the following portions of 40 CFR 60, Subpart OOO.

- (1) 40 CFR 60.670
- (2) 40 CFR 60.671
- (3) 40 CFR 60.672
- (4) 40 CFR 60.673
- (5) 40 CFR 60.675
- (6) 40 CFR 60.676
- (7) Table 1
- (8) Table 2
- (9) Table 3

The requirements of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated as 326 IAC 12-1, apply to the limestone handling and storage system for the flue gas desulfurization system except as otherwise specified in 40 CFR 60, Subpart OOO.

- (d) The SI propane emergency engine and SI propane emergency pump, identified as ENG-04 and ENG-05 respectively, are subject to the New Source Performance Standards for Stationary Spark Ignition Internal Combustion Engines 40 CFR 60, Subpart JJJJ and 326 IAC 12, because these units commenced construction after June 12, 2006, were manufactured on or after January 1, 2009, with a maximum engine power greater than 19 KW (25 HP). The units subject to this rule includes the following:
- (1) One (1) SI emergency engine, identified as ENG-04 with maximum capacity of 67 Hp (50 kW), manufactured by Power Solutions International, fired with LPG, model year 2018 exhausting outside the building. The engine is used provide backup power to a microwave tower during the loss of power.
  - (2) One (1) SI propane emergency generator, identified as ENG-05, permitted in 2024, with a maximum capacity of 229 brake horsepower, using no controls, and exhausting to atmosphere.

These units are subject to the following portions of 40 CFR 60, Subpart JJJJ:

- (1) 40 CFR 60.4230
- (2) 40 CFR 60.4233
- (3) 40 CFR 60.4237
- (4) 40 CFR 60.4243(a), (b)(1), (d), (d), (g), (i)
- (5) 40 CFR 60.4245(a), (b)
- (6) 40 CFR 60.4246(a)
- (7) 40 CFR 60.4248
- (8) Tabel 3

The requirements of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated as 326 IAC 12-1, apply to the emergency engine and SI propane emergency generator except as otherwise specified in 40 CFR 60, Subpart JJJJ.

- (e) The two (2) Diesel Fired Emergency Generators, identified as ENG-01 and ENG-02, the Emergency Diesel Fire Pump, identified as ENG-03, and the four (4) no.2 fuel oil fired generators (3A through 3D) are not subject to the New Source Performance Standards for Stationary Spark Ignition Internal Combustion Engines 40 CFR 60, Subpart JJJJ and 326 IAC 12, because the generators are not spark ignition engines.
- (f) The Diesel Fired Emergency Generators, identified as ENG-01 and ENG-02, are subject to the New Source Performance Standards for Stationary Compression Ignition Internal Combustion Engines, 40 CFR 60, Subpart IIII and 326 IAC 12, because these units were constructed after July 11, 2005 and manufactured after April 1, 2006 and are not fire pump engines.

ENG-01 and ENG-02 are subject to the following portions of 40 CFR 60, Subpart IIII:

- (1) 40 CFR 60.4200(a)(2)(i), (a)(4)
- (2) 40 CFR 60.4205(b)
- (3) 40 CFR 60.4207 (b)
- (4) 40 CFR 60.4208
- (5) 40 CFR 60.4209(a)
- (6) 40 CFR 60.4211(a), (c), (f)(1), (f)(2)(i), (f)(3), (g)(2)
- (7) 40 CFR 60.4212
- (8) 40 CFR 60.4214(b)
- (9) 40 CFR 60.4218
- (10) 40 CFR 60.4219
- (11) Table 5
- (12) Table 8

The requirements of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated as 326 IAC 12-1, apply to the Diesel Fired Emergency Generators ENG-01 and ENG-02 except as otherwise specified in 40 CFR 60, Subpart IIII.

- (g) The requirements of the New Source Performance Standard for Stationary Compression ignition internal Combustion Engines 40 CFR 60, Subpart IIII and 326 IAC 12, are not included in the permit for the SI Emergency Engine and SI Emergency Generator, identified as ENG-04 and ENG-05 respectively, because the generators and engine are not compression ignition engines.
- (h) The requirements of the New Source Performance Standard for Stationary Compression ignition internal Combustion Engines 40 CFR 60, Subpart IIII and 326 IAC 12, are not included in the permit for the Emergency Diesel Fire Pump Engine, identified as ENG-03 since the emergency fire pump engine was not manufactured as a certified National Fire Prevention Association (NFPA) fire pump engine after July 1, 2006.
- (i) The requirements of the New Source Performance Standard for Stationary Compression Ignition Internal Combustion Engines 40 CFR 60, Subpart IIII and 326 IAC 12, are not included in the permit for the four (4) no.2 fuel oil fired generators (3A through 3D), because each of these generators were constructed prior to July 11, 2005 and manufactured prior to April 1, 2006. Each of these engines were constructed in 1972.
- (j) There are no other New Source Performance Standards (40 CFR Part 60) and 326 IAC 12 included in the permit.

**National Emission Standards for Hazardous Air Pollutants (NESHAP):**

- (a) The National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and process Heaters, 40 CFR 63, Subpart DDDDD, was initially promulgated on September 13, 2004. On June 19, 2007, the United States Court of Appeals for the District of Columbia Circuit vacated and remanded the standards. New rule amendments were promulgated on March 21, 2011 (76 FR 15608). On May 18, 2011, the EPA issued a delay of the effective dates for Subpart DDDDD until the proceedings for judicial review of the rules were completed or the EPA completed its reconsideration of the rule, whichever was earlier (76 FR 28662). On January 9, 2012, the US District Court for the District of Columbia issued an order (*Sierra Club vs. U.S. EPA*, No. 11-1278) to vacate and remand the Delay Notice issued on May 18, 2011. Therefore, the provisions of 40 CFR 63, Subpart DDDDD, as issued on March 21, 2011 are effective and shall be included in the permit as applicable.

The No. 2 fuel oil-fired boiler, identified as Aux is subject to the National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, 40 CFR 63.7485, Subpart DDDDD because it is considered existing boiler or process heater located at a major source of HAP. The unit subject to this rule includes the following:

- (1) One (1) Auxiliary Boiler, identified as emission unit Aux, with a maximum heat input capacity of 72.76 MMBtu/hr fired with distillate oil and exhausting out one stack identified as stack Aux-1. The Auxiliary boiler was constructed before 1968.

[Under NESHAP 40 CFR 63, Subpart DDDDD, this unit is part of an affected source]

This emission unit identified as emission unit Aux is subject to the following portions of 40 CFR 63, Subpart DDDDD:

- (1) 40 CFR 63.7485
- (2) 40 CFR 63.7490(a)(1)
- (3) 40 CFR 63.7490(d)
- (4) 40 CFR 63.7499(o)
- (5) 40 CFR 63.7500(c)

- (6) 40 CFR 63.7500(f)
- (7) 40 CFR 63.7515(d)
- (8) 40 CFR 63.7550(b)
- (9) 40 CFR 63.7550(c)(1)
- (10) 40 CFR 63.7550(c)(5)(vi)
- (11) 40 CFR 63.7550(c)(5)(xvii)
- (12) 40 CFR 63.7550(h)(3)
- (13) 40 CFR 63.7555(a)(1)
- (14) 40 CFR 63.7560
- (15) 40 CFR 63.7575

The provisions of 40 CFR 63, Subpart A – General Provisions, which are incorporated as 326 IAC 20-1-1, apply to the facility described in this section except when otherwise specified in 40 CFR 63, Subpart DDDDD.

- (2) Boilers, identified as Boiler No. 1, Boiler No. 2 are not subject to the requirements of 40 CFR 63, Subpart DDDDD, pursuant to 40 CFR 63.7491 because these boilers are electric utility steam generating units (EGU) that are covered by NESHAP 40 CFR 63, Subpart UUUUU.
- (b) The four (4) no.2 fuel oil fired generators (3A through 3D) are subject to the National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines, 40 CFR 63, Subpart ZZZZ and 326 IAC 20-82, because these four (4) generators are stationary RICE located in a major source of HAPs. The units subject to this rule include the following:
- (1) One (1) no. 2 fuel oil-fired generator, identified as Unit No. 3A, installed in 1972, with a nominal heat input capacity of 30 million Btu per hour (MMBtu/hr), using an oxidation catalyst installed in 2017 as control, and exhausting to stack 3A.
  - (2) One (1) no. 2 fuel oil-fired generator, identified as Unit No. 3B, installed in 1972, with a nominal heat input capacity of 30 million Btu per hour (MMBtu/hr), using an oxidation catalyst installed in 2017 as control, and exhausting to stack 3B.
  - (3) One (1) no. 2 fuel oil-fired generator, identified as Unit No. 3C, installed in 1972, with a nominal heat input capacity of 30 million Btu per hour (MMBtu/hr), using an oxidation catalyst installed in 2017 as control, and exhausting to stack 3C.
  - (4) One (1) no. 2 fuel oil-fired generator, identified as Unit No. 3D, installed in, with a nominal heat input capacity of 30 million Btu per hour (MMBtu/hr), using an oxidation catalyst installed in 2017 as control, and exhausting to stack 3D.

These emission units are subject to the following portions of 40 CFR 63, Subpart ZZZZ:

- (1) 40 CFR 63.6580
- (2) 40 CFR 63.6585(a), (b)
- (3) 40 CFR 63.6590(a)(1)(i)
- (4) 40 CFR 63.6595(a)(1), (c)
- (5) 40 CFR 63.6600(d)
- (6) 40 CFR 63.6604(a)
- (7) 40 CFR 63.6605
- (8) 40 CFR 63.6610(a)
- (9) 40 CFR 63.6615
- (10) 40 CFR 63.6620(a), (b)(4), (d), (e), (i)
- (11) 40 CFR 63.6625(b) and (g)
- (12) 40 CFR 63.6630(a), (b), (c)
- (13) 40 CFR 63.6635
- (14) 40 CFR 63.6640(a), (b)

- (15) 40 CFR 63.6645(a), (b), (g), (h)
- (16) 40 CFR 63.6650(b), (c), (d), (f)
- (17) 40 CFR 63.6655(a), (b), (d)
- (18) 40 CFR 63.6660
- (19) 40 CFR 63.6665
- (20) 40 CFR 63.6670
- (21) 40 CFR 63.6675
- (22) Table 2c, item 5
- (23) Table 3, item 4
- (24) Table 4, Items 1 and 3
- (25) Table 5, item 2
- (26) Table 6, item 10
- (27) Table 7, item 1
- (28) Table 8

The requirements of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated as 326 IAC 20-1, apply to the units except as otherwise specified in 40 CFR 63, Subpart ZZZZ.

- (c) ENG-01, ENG-02, ENG-03, ENG-04, and ENG-05 are subject to the National Emission Standards for Hazardous Air Pollutants (NESHAP), 326 IAC 20-82, 40 CFR 63, Subpart ZZZZ (Stationary Reciprocating Internal Combustion Engines) because these units are stationary RICE located at a major source of HAP emissions. The units subject to this rule include the following:

- (1) One (1) Diesel Fired Emergency Generator, identified as ENG-01 with maximum capacity of 156.9 HP (100 kW), CI ICE with a displacement 4.4 liters, Manufactured by Caterpillar Model Year 2007, Model D100-6, constructed in 2007, exhausting outside the building. This generator is located in the switch yard and is operated as backup for the black start diesel aux feed.
- (2) One (1) Diesel Fired Emergency Engine, identified as ENG-02, with maximum capacity of 713 Hp (450 kW), CI ICE with a displacement 15.2 liters, Manufactured by Caterpillar, Model Year 2007, Model C15DITA, constructed in 2007, exhausting outside the building. This engine is used to quench the flue gas if the scrubber should fail.
- (3) One (1) Emergency Diesel Fire Pump Engine, identified as ENG-03, with maximum capacity of 430 Hp (321 kW) CI, manufactured by Caterpillar, Model Year 2005, Model 3406, exhausting outside the building.
- (4) One (1) SI emergency engine, identified as ENG-04 with maximum capacity of 67 Hp (50 kW), manufactured by Power Solutions International, fired with LPG, model year 2018 exhausting outside the building. The engine is used to provide backup power to a microwave tower during the loss of power.
- (5) One (1) SI propane emergency pump, identified as ENG-05, permitted in 2024, with a maximum capacity of 229 brake horsepower, using no controls, and exhausting to atmosphere.

The Diesel Fired Emergency Engine, ENG-01 is subject to the following portions of 40 CFR 63, Subpart ZZZZ:

- (1) 40 CFR 63.6580
- (2) 40 CFR 63.6585
- (3) 40 CFR 63.6590(a)(2)(ii), (c)(7)
- (4) 40 CFR 63.6595(a)(4)
- (5) 40 CFR 63.6640(f)(1), (2)(i), and (3)
- (6) 40 CFR 63.6665
- (7) 40 CFR 63.6670
- (8) 40 CFR 63.6675

(9) Table 8

The Diesel Fired Emergency Engine, ENG-02 is subject to the following portions of 40 CFR 63, Subpart ZZZZ:

- (1) 40 CFR 63.6580
- (2) 40 CFR 63.6585
- (3) 40 CFR 63.6590(a)(2)(i), (b)(1)(i)
- (4) 40 CFR 63.6595(a)(3), (c)
- (5) 40 CFR 63.6600(c)
- (6) 40 CFR 63.6605(b)
- (7) 40 CFR 63.6640(f)(1), (f)(2)(i), (f)(3)
- (8) 40 CFR 63.6645(f)
- (9) 40 CFR 63.6665
- (10) 40 CFR 63.6670
- (11) 40 CFR 63.6675
- (12) Table 8

The Emergency Diesel Fire Pump Engine, ENG-03 is subject to the following portions of 40 CFR 63, Subpart ZZZZ:

- (1) 40 CFR 63.6580
- (2) 40 CFR 63.6585
- (3) 40 CFR 63.6590(a)(1)(ii)
- (4) 40 CFR 63.6595(a)(1), (c)
- (5) 40 CFR 63.6602
- (6) 40 CFR 63.6604(b)
- (7) 40 CFR 63.6605
- (8) 40 CFR 63.6625(e)(f)(h)(i)
- (9) 40 CFR 63.6640(f)(1), (2)(i), (3)
- (10) 40 CFR 63.6655(f)
- (11) 40 CFR 63.6665
- (12) 40 CFR 63.6670
- (13) 40 CFR 63.6675
- (14) Table 2c item 1
- (15) Table 8

The SI propane emergency engine, ENG-04 is subject to the following portions of 40 CFR 63, Subpart ZZZZ:

- (1) 40 CFR 63.6580
- (2) 40 CFR 63.6585
- (3) 40 CFR 63.6590(a)(2)(ii), (c)(6)
- (4) 40 CFR 63.6595(a)(5), (c)
- (5) 40 CFR 63.6640(f)(1), (2)(i), (3)
- (6) 40 CFR 63.6665
- (7) 40 CFR 63.6670
- (8) 40 CFR 63.6675
- (9) Table 8

The SI propane emergency pump, ENG-05 is subject to the following portions of 40 CFR 63, Subpart ZZZZ:

- (1) 40 CFR 63.6580
- (2) 40 CFR 63.6585
- (3) 40 CFR 63.6590(a)(2)(ii), (c)(6)
- (4) 40 CFR 63.6595(a)(5), (c)

- (5) 40 CFR 63.6640(f)(1), (2)(i), (3)
- (6) 40 CFR 63.6665
- (7) 40 CFR 63.6670
- (8) 40 CFR 63.6675
- (9) Table 8

The requirements of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated as 326 IAC 20-1, apply to the units except as otherwise specified in 40 CFR 63, Subpart ZZZZ.

- (d) Boilers No. 1 and No. 2 are subject to the National Emission Standards for Hazardous Air Pollutants for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units 40 CFR 63, Subpart UUUUU, which is incorporated by reference as 326 IAC 20-89-1, because the source owns and operates a coal-fired EGU. The units subject to this rule includes the following:

- (1) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 1, installed in 1967, using #2 fuel oil for startup, shutdown, and stabilization purposes, with a nominal heat input capacity of 4,802 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, a flue gas desulfurization (FGD) system for control of SO<sub>2</sub>, and exhausting to stack 1. Stack 1 has continuous emissions monitors (CEMs) for nitrogen oxides (NO<sub>x</sub>), sulfur dioxide (SO<sub>2</sub>), and particulate matter (PM). Boiler No. 1 was configured with a low NO<sub>x</sub> burner in 1993. Selective Catalytic Oxidation (SCR) to control NO<sub>x</sub>, and Dry Sorbent Injection System to Control SO<sub>3</sub> constructed in 2015. The Boiler is equipped with a PM CEMS, SO<sub>2</sub> CEMS, and NO<sub>x</sub> CEMS.
- (2) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 2, installed in 1968, using #2 fuel oil for startup, shutdown, and stabilization purposes, with a nominal heat input capacity of 4,802 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, a flue gas desulfurization (FGD) system for control of SO<sub>2</sub>, and exhausting to stack 2. Stack 2 has continuous emissions monitors (CEMs) for nitrogen oxides (NO<sub>x</sub>), sulfur dioxide (SO<sub>2</sub>), and particulate matter (PM) and a continuous opacity monitor (COM). The COM will no longer be used for permit compliance purposes as of April 16, 2016 or when the PM CEM is installed, certified, and operating to measure PM pursuant to this permit. Boiler No. 2 was configured with a low NO<sub>x</sub> burner in 1993. Selective Catalytic Oxidation (SCR) to control NO<sub>x</sub>, and Dry Sorbent Injection System to Control SO<sub>3</sub>, installed by 2015.

These emission units are subject to the following portions of 40 CFR 63, Subpart UUUUU:

- (1) 40 CFR 63.9981
- (2) 40 CFR 63.9982(a)(1)
- (3) 40 CFR 63.9982(d)
- (4) 40 CFR 63.9984(b)
- (5) 40 CFR 63.9984(f)
- (6) 40 CFR 63.9991(a)(1)
- (7) 40 CFR 63.9991(b)
- (8) 40 CFR 63.9991(c)
- (9) 40 CFR 63.10000(a)
- (10) 40 CFR 63.10000(b)
- (11) 40 CFR 63.10000(c)(1)(i)
- (12) 40 CFR 63.10000(c)(1)(iii)
- (13) 40 CFR 63.10000(c)(1)(iv)
- (14) 40 CFR 63.10000(c)(1)(v)
- (15) 40 CFR 63.10000(c)(1)(vi)
- (16) 40 CFR 63.10000(d) - (g)
- (17) 40 CFR 63.10000(i) - (l)



- (18) 40 CFR 63.10005(a)(1)
- (19) 40 CFR 63.10005(a)(2)(i)
- (20) 40 CFR 63.10005(a)(2)(ii)
- (21) 40 CFR 63.10005(b)
- (22) 40 CFR 63.10005(d)(1)
- (23) 40 CFR 63.10005(d)(3)
- (24) 40 CFR 63.10005(e)
- (25) 40 CFR 63.10005(f)
- (26) 40 CFR 63.10005(h)(1)(i)
- (27) 40 CFR 63.10005(h)(2)
- (28) 40 CFR 63.10005(j)
- (29) 40 CFR 63.10005(k)
- (30) 40 CFR 63.10006(b)(1)
- (31) 40 CFR 63.10006(c)
- (32) 40 CFR 63.10006(f) - (j)
- (33) 40 CFR 63.10007(a)(1)
- (34) 40 CFR 63.10007(a)(2)
- (35) 40 CFR 63.10007(b)
- (36) 40 CFR 63.10007(d) - (g)
- (37) 40 CFR 63.10009(a)(1)
- (38) 40 CFR 63.10009(a)(2)(i)
- (39) 40 CFR 63.10009(a)(2)(ii)
- (40) 40 CFR 63.10009(b) - (j)
- (41) 40 CFR 63.10010(a)(1)
- (42) 40 CFR 63.10010(b)
- (43) 40 CFR 63.10010(c)
- (44) 40 CFR 63.10010(d)
- (45) 40 CFR 63.10010(f)
- (46) 40 CFR 63.10010(g)
- (47) 40 CFR 63.10010(i)
- (48) 40 CFR 63.10010(l)
- (49) 40 CFR 63.10011
- (50) 40 CFR 63.10020
- (51) 40 CFR 63.10021(a)
- (52) 40 CFR 63.10021(b)
- (53) 40 CFR 63.10021(d)(1)
- (54) 40 CFR 63.10021(d)(2)
- (55) 40 CFR 63.10021(e) - (i)
- (56) 40 CFR 63.10022
- (57) 40 CFR 63.10030
- (58) 40 CFR 63.10031
- (59) 40 CFR 63.10032
- (60) 40 CFR 63.10033
- (61) 40 CFR 63.10041
- (62) 40 CFR 63.10042
- (63) Table 2 item 1
- (64) Table 3 items 1, 3, 4
- (65) Table 5 items 1, 4, 5
- (66) Table 8
- (67) Appendix A

The requirements of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated as 326 IAC 20-1, apply to the Boilers No. 2 and 4 except as otherwise specified in 40 CFR 63, Subpart UUUUU.

- (e) The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAPs) for National Emission Standards for Halogenated Solvent Cleaning 40 CFR 63, Subpart T and 326 IAC 20-6-1 because no halogenated HAP solvents listed in 40 CFR 63.460(a).

- (f) There are no other National Emission Standards for Hazardous Air Pollutants under 40 CFR 63, 326 IAC 14 and 326 IAC 20 included in the permit.

**Acid Rain Permit:**

Pursuant to 40 CFR 72 through 40 CFR 78 and 326 IAC 21 (Acid Rain Program), the acid rain permit for this source is incorporated by reference into this Part 70 Permit. Pursuant to 326 IAC 21 (Acid Deposition Control), the Permittee shall comply with all provisions of the Acid Rain permit issued for this source, and any other applicable requirements contained in 40 CFR 72 through 40 CFR 78.

**Cross-State Air Pollutant Rule (CSAPR):**

The preamble of the CSAPR regulations, promulgated on August 8, 2011, states that the requirements established in the CSAPR trading program are applicable requirements that must be included in a source Title V permit pursuant to 40 CFR, Part 70 and 71.

The CSAPR became effective on 1 January 2015 to reduce annual NOX emissions, ozone (O3) season NOX emissions, and annual SO2 emissions from fossil fuel-fired electric generating facilities in 28 states, including Indiana. Similar to the Acid Rain Program, CSAPR implemented a market-based approach for lowering emissions by imposing program-wide caps and providing an initial allocation of allowances to existing subject sources. Unlike the Acid Rain Program, CSAPR sets aside a percentage of the allowance budgets to provide to new units.

On March 15, 2021, EPA finalized the Revised Cross-State Air Pollution Rule (CSAPR) Update in order to resolve 21 states' outstanding interstate pollution transport obligations for the 2008 ozone National Ambient Air Quality Standards (NAAQS) (i.e., the 2008 ozone "good neighbor" provisions). Under this new regulation, power plants in 12 states will be required to participate in a new CASPR NOX Ozone Season Group 3 Trading Program (40 CFR 97, Subpart GGGGG). The new Group 3 trading program established in the rule was implemented starting May 1, 2021 (the first day of the 2021 ozone season), in which the Federal Implementation Plans (FIPs) will reduce NOx emissions from power plants in 12 states, including Indiana.

Pursuant to 40 CFR 97.804(a)(1), the Boiler No. 1 and Boiler No. 2 is subject to the CSAPR NOx Ozone Group 3 Trading Program because these are stationary, fossil-fuel-fired combustion boilers serving at any time, on or after January 1, 2005, a generator with nameplate capacity of more than 25 MW producing electricity for sale.

**Transport Rule Monitoring Provisions**

The natural gas-fired Boiler No. 1 and Boiler No. 2 are subject to the requirements for the TR NOx Annual Trading Program, the TR NOx Ozone Season Trading Program, and the TR SO2 Group 1 Trading Program. The TR subject unit and the unit-specific monitoring provisions at this source are identified in the following table.

Parameter	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR, Part 75, Subpart B (for SO2 monitoring) & 40 CFR, Part 75, Subpart H (for NOx Monitoring)	Excepted monitoring system requirements for gas-fired & oil-fired units pursuant to 40 CFR, Part 75, Appendix D	Excepted monitoring system requirements for gas-fired & oil-fired peaking units pursuant to 40 CFR, Part 75, Appendix E	Low Mass Emissions excepted monitoring (LME) requirements for gas-fired & oil-fired units pursuant to 40 CFR 75.19	EPA-approved alternative monitoring system requirements pursuant to 40 CFR, Part 75, Subpart E
SO2	X	--	--	--	--
NOx	X	--	--	--	--
Heat Input	X	--	--	--	--

- (a) The above description of the monitoring used by a unit does not change, create an exemption from, or otherwise affect the monitoring, recordkeeping, and reporting requirements applicable to the unit under 40 CFR 97.430 through 97.435 (TR NO<sub>x</sub> Annual Trading Program), 97.530 through 97.535 (TR NO<sub>x</sub> Ozone Season Trading Program), and 97.630 through 97.635 (TR SO<sub>2</sub> Group 1 Trading Program), as applicable. The monitoring, recordkeeping and reporting requirements applicable to each unit are included below in the standard conditions for the applicable TR trading programs.
- (b) Owners and operators must submit to the Administrator a monitoring plan for each unit in accordance with 40 CFR 75.53, 75.62 and 75.73, as applicable. The monitoring plan for each unit is available at the EPA's website at <http://www.epa.gov/airmarkets/emissions/monitoringplans.html>.
- (c) Owners and operators that want to use an alternative monitoring system must submit to the Administrator a petition requesting approval of the alternative monitoring system in accordance with 40 CFR part 75, subpart E and 40 CFR 75.66 and 97.435 (TR NO<sub>x</sub> Annual Trading Program), 97.535 (TR NO<sub>x</sub> Ozone Season Trading Program), and 97.635 (TR SO<sub>2</sub> Group 1 Trading Program), as applicable. The Administrator's response approving or disapproving any petition for an alternative monitoring system is available on the EPA's website at <http://www.epa.gov/airmarkets/emissions/petitions.html>.
- (d) Owners and operators that want to use an alternative to any monitoring, recordkeeping, or reporting requirement under 40 CFR 97.430 through 97.434 (TR NO<sub>x</sub> Annual Trading Program), 97.530 through 97.534 (TR NO<sub>x</sub> Ozone Season Trading Program), and 97.630 through 97.634 (TR SO<sub>2</sub> Group 1 Trading Program), as applicable, must submit to the Administrator a petition requesting approval of the alternative in accordance with 40 CFR 75.66 and 97.435 (TR NO<sub>x</sub> Annual Trading Program), 97.535 (TR NO<sub>x</sub> Ozone Season Trading Program), and 97.635 (TR SO<sub>2</sub> Group 1 Trading Program), as applicable. The Administrator's response approving or disapproving any petition for an alternative to a monitoring, recordkeeping, or reporting requirement is available on EPA's website at <http://www.epa.gov/airmarkets/emissions/petitions.html>.
- (e) The descriptions of monitoring applicable to the unit included above meet the requirement of 40 CFR 97.430 through 97.434 (TR NO<sub>x</sub> Annual Trading Program), 97.530 through 97.534 (TR NO<sub>x</sub> Ozone Season Trading Program), and 97.630 through 97.634 (TR SO<sub>2</sub> Group 1 Trading Program), as applicable, and therefore minor permit modification procedures, in accordance with 40 CFR 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B), may be used to add to or change this unit's monitoring system description.

**Compliance Assurance Monitoring (CAM):**

- (a) Pursuant to 40 CFR 64.2, Compliance Assurance Monitoring (CAM) is applicable to each existing pollutant-specific emission unit that meets the following criteria:
  - (1) has a potential to emit before controls equal to or greater than the major source threshold for the regulated pollutant involved;
  - (2) is subject to an emission limitation or standard for that pollutant (or a surrogate thereof); and
  - (3) uses a control device, as defined in 40 CFR 64.1, to comply with that emission limitation or standard.
- (b) Pursuant to 40 CFR 64.2(b)(1)(i), emission limitations or standards proposed after November 15, 1990 pursuant to a NSPS or NESHAP under Section 111 or 112 of the Clean Air Act are exempt from the requirements of CAM. Therefore, an evaluation was not conducted for any emission limitations or standards proposed after November 15, 1990 pursuant to a NSPS or NESHAP under Section 111 or 112 of the Clean Air Act.

- (c) Pursuant to 40 CFR 64.2(b)(1)(iii), Acid Rain requirements pursuant to Sections 404, 405, 406, 407(a), 407(b), or 410 of the Clean Air Act are exempt emission limitations or standards. Therefore, CAM was not evaluated for emission limitations or standards for SO<sub>2</sub> and NO<sub>x</sub> under the Acid Rain Program.
- (d) Pursuant to 40 CFR 64.3(d), if a continuous emission monitoring system (CEMS) is required pursuant to other federal or state authority, the owner or operator shall use the CEMS to satisfy the requirements of CAM according to the criteria contained in 40 CFR 64.3(d).

The following table is used to identify the applicability of CAM to each emission unit and each emission limitation or standard for a specified pollutant based on the criteria specified under 40 CFR 64.2:

Emission Unit/Pollutant	Control Device	Applicable Emission Limitation	Uncontrolled PTE (tons/year)	Controlled PTE (tons/year)	CAM Applicable (Y/N)	Large Unit (Y/N)
Boiler No. 1 (PM)	ESP	326 IAC 6-2-3	>100	>100	N <sup>1</sup>	--
Boiler No. 1 (PM <sub>10</sub> )	ESP	none	>100	>100	N	--
Boiler No. 1 (SO <sub>2</sub> )	FGD	326 IAC 7-4-8	>100	>100	N <sup>1</sup>	--
Boiler No. 2 (PM)	ESP	326 IAC 6-2-3	>100	>100	N <sup>1</sup>	--
Boiler No. 2 (PM <sub>10</sub> )	ESP	none	>100	>100	N	--
Boiler No. 2 (SO <sub>2</sub> )	FGD	326 IAC 7-4-8	>100	>100	N <sup>1</sup>	--
Baghouse Separator EP-01 PM	BH	326 IAC 6-3-2 326 IAC 2-2	>100	<100	Y	N
Baghouse Separator EP-01 PM <sub>10</sub>	BH	326 IAC 2-2	>100	<100	Y	N
Baghouse Separator EP-01 PM <sub>2.5</sub>	BH	326 IAC 2-2	>100	<100	Y	N
Baghouse Separator EP-02 PM	BH	326 IAC 6-3-2 326 IAC 2-2	>100	<100	Y	N
Baghouse Separator EP-02 PM <sub>10</sub>	BH	326 IAC 2-2	>100	<100	Y	N
Baghouse Separator EP-02 PM <sub>2.5</sub>	BH	326 IAC 2-2	>100	<100	Y	N
Baghouse Separator EP-03 PM	BH	326 IAC 6-3-2 326 IAC 2-2	>100	<100	Y	N
Baghouse Separator EP-03 PM <sub>10</sub>	BH	326 IAC 2-2	>100	<100	Y	N
Baghouse Separator EP-03 PM <sub>2.5</sub>	BH	326 IAC 2-2	>100	<100	Y	N
Baghouse Separator EP-04 PM	BH	326 IAC 6-3-2 326 IAC 2-2	>100	<100	Y	N
Baghouse Separator EP-04 PM <sub>10</sub>	BH	326 IAC 2-2	>100	<100	Y	N
Baghouse Separator EP-04 PM <sub>2.5</sub>	BH	326 IAC 2-2	>100	<100	Y	N
Spare Exhauster EP-05 PM	BH	326 IAC 2-2 326 IAC 6-3-2	>100	<100	Y	N
Spare Exhauster EP-05 PM <sub>10</sub>	BH	326 IAC 2-2	>100	<100	Y	N
Spare Exhauster EP-05 PM <sub>2.5</sub>	BH	326 IAC 2-2	>100	<100	Y	N

Emission Unit/Pollutant	Control Device	Applicable Emission Limitation	Uncontrolled PTE (tons/year)	Controlled PTE (tons/year)	CAM Applicable (Y/N)	Large Unit (Y/N)
Fly Ash Silo#1 EP-06 PM	BH	326 IAC 2-2 326 IAC 6-3-2	>100	<100	Y	N
Fly Ash Silo#1 EP-06 PM10	BH	326 IAC 2-2	>100	<100	Y	N
Fly Ash Silo#1 EP-06 PM2.5	BH	326 IAC 2-2	>100	<100	Y	N
Fly Ash Silo#2 EP-07 PM	BH	326 IAC 2-2 326 IAC 6-3-2	>100	<100	Y	N
Fly Ash Silo#2 EP-07 PM10	BH	326 IAC 2-2	>100	<100	Y	N
Under the Part 70 Permit program (40 CFR 70), PM is not a regulated air pollutant.						
Uncontrolled PTE (tpy) and controlled PTE (tpy) are evaluated against the Major Source Threshold for each pollutant. Major Source Threshold for regulated air pollutants (PM10, PM2.5, SO2, NOx, VOC, and CO) is 100 tpy, for a single HAP ten (10) tpy, and for total HAPs twenty-five (25) tpy.						
PM*	For limitations under 326 IAC 6-3-2, 326 IAC 6.5, and 326 IAC 6.8, IDEM OAQ uses PM as a surrogate for the regulated air pollutant PM10. Therefore, uncontrolled PTE and controlled PTE reflect the emissions of the regulated air pollutant PM10.					
N 1	A continuous compliance determination method, which provides data either in units of the standard or correlated directly to the compliance limit, is already specified in the Part 70 permit. Therefore, the emission limitation or standard is exempt from the requirements of 40 CFR Part 64, CAM.					
Controls: BH = Baghouse, C = Cyclone, DC = Dust Collection System, RTO = Regenerative or Recuperative Thermal Oxidizer, WS = Wet Scrubber, ESP = Electrostatic Precipitator, ST = Sorbant Trap						
Emission units without air pollution controls are not subject to CAM. Therefore, they are not listed.						

Although Boilers 1 and 2 have PTE equal to or greater than the major level of 100 tons per year for NOx, and CO, they are not subject to CAM for these pollutants because there are no NOx and CO limitations or standards applicable to these boilers.

Based on this evaluation, the requirements of 40 CFR Part 64, CAM, are applicable the Boilers, the Baghouse Separators, and the Fly Ash Silos as indicated in the above table for PM, PM10 and PM2.5. A CAM plan was submitted as part of a previous permit application and the Compliance Determination and Monitoring Requirements section includes a detailed description of the CAM requirements.

**State Rule Applicability - Entire Source**

State rule applicability for this source has been reviewed as follows:

**326 IAC 1-6-3 (Preventive Maintenance Plan)**

The source is subject to 326 IAC 1-6-3.

**326 IAC 1-5-2 (Emergency Reduction Plans)**

The source is subject to 326 IAC 1-5-2.

**326 IAC 2-2 (PSD) and 326 IAC 2-3 (Emission Offset)**

The source was originally constructed in 1967, which is prior to the promulgation of PSD Rules on August 7, 1977. The source is an existing major under PSD, emitting PM above 100 tons per year from its initial operation in 1967, but the source never went through PSD permitting. Therefore, all modifications after August 7, 1977 were evaluated under PSD Significant Emission Rate (SER).

2008 Modification

In order to render the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)) not applicable to the 2008 Modification permitted under SSM No. 165-22733-00001, issued on January 8, 2008, the Permittee shall comply with the following:

- (a) The total limestone received shall not exceed 509,000 tons per twelve (12) consecutive month period with compliance determined at the end of each month.
- (b) The PM/PM10 emissions from the lime handling operations shall not exceed the emission limits listed in the table below:

<b>Emission Point</b>	<b>Unit Description</b>	<b>PM Emission Limit (lbs/ton)</b>	<b>PM10 Emission Limit (lbs/ton)</b>
EP-L1	Railcar/Truck Unloading	2.50E-05	2.50E-05
EP-L2	Hoppers	7.50E-04	2.75E-04
EP-L2	Belt Feeders	7.50E-04	2.75E-04
EP-L3	Conveyor LH-1	1.50E-03	5.50E-04
EP-L4	Reclaim Hoppers	7.50E-04	2.75E-04
EP-L4	Belt Feeders	7.50E-04	2.75E-04
EP-L18a, b, c	Conveyor LH-2	7.50E-04	2.75E-04
EP-L18a, b, c	Conveyor LH-3	7.50E-04	2.75E-04
EP-L16	Day Bin Unit 1	3.00E-03	1.10E-03
EP-L17	Day Bin Unit 2	3.00E-03	1.10E-03

- (c) The emissions from the following units of the limestone handling system shall be controlled by the control method specified in the table below:

<b>Emission Point</b>	<b>Unit</b>	<b>Control Method</b>
EP-L1	Railcar/Truck Unloading Operation	Fog Dust Suppression
EP-L2	Hoppers Belt Feeders LHBF-1 and LHBF-2	Fog Dust Suppression
EP-L3	Conveyor LH-1	Telescoping Chute
EP-L4	Reclaim Hoppers Belt Feeders LHBF-3 and LHBF-4	Fog Dust Suppression
EP-L18a, b, c	Conveyors LH-2 and LH-3	Fog Dust Suppression

- (d) The total gypsum processed shall not exceed 900,528 tons per twelve (12) consecutive month period with compliance determined at the end of each month.
- (e) The PM/PM10 emissions from the gypsum conveying system shall not exceed the emission limits listed in the table below:

<b>Unit Description</b>	<b>PM Emission Limit (lbs/ton)</b>	<b>PM10 Emission Limit (lbs/ton)</b>
Gypsum Conveying System	0.00014	0.000046

- (f) The limestone and gypsum stockpiles shall be controlled by wet suppression. The suppressant shall be applied in a manner and at a frequency sufficient to ensure compliance with 326 IAC 2-2.

Compliance with these limits, shall limit the potential to emit of PM and PM10 to less than 25 tons and 15 tons per twelve (12) consecutive month period, respectively, and shall render the

requirements of 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)) not applicable to the 2008 Modification permitted under SSM No. 165-22733-00001.

2012 Modification and 2013 Modification

In order to render the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)) not applicable to the 2012 Modification permitted under SSM No. 165-32045-00001, issued on September 5, 2012 and as modified under SSM No. 165-33709-00001, issued on November 27, 2013, the Permittee shall comply with the following:

- (a) Fly ash unloaded from the fly ash silo shall either be unloaded wet into open trucks with the ash having a moisture content of not less than 15% or unloaded dry into enclosed trucks using the telescoping chute to vent emissions back to the fly ash silo bin vent filter.
- (b) The PM, PM<sub>10</sub>, and PM<sub>2.5</sub> emissions from the Activity on Storage Pile shall be controlled by maintaining the average moisture content of the fixated ash not less than 15% moisture content and applying water to the pile as needed to prevent dusting.
- (c) The PM, PM<sub>10</sub>, and PM<sub>2.5</sub> emissions from the limestone, dry sorbent, activated carbon, dry ash and ash fixation systems shall not exceed the emission limits listed in the table below:

Emission Point	Unit Description	PM Emission Limit (lbs/hr)	PM10 Emission Limit (lbs/hr)	PM2.5 Emission Limit (lbs/hr)
EP-01(LS)	Limestone Silo	0.094	0.094	0.094
EP-02(LS)	Limestone Surge Bin	0.097	0.097	0.097
EP-01(DSI)	Unit 1 DSI Silo #1	0.043	0.043	0.043
EP-03(DSI)	Unit 2 DSI Silo #1	0.043	0.043	0.043
EP-05A(DSI)	Sorbent Silo Weight Feeders	0.0086	0.0086	0.0086
EP-05B(DSI)	Sorbent Silo Weight Feeders			
EP-06A(DSI)	Sorbent Silo Weight Feeders	0.0086	0.0086	0.0086
EP-06B(DSI)	Sorbent Silo Weight Feeders			
EP-01(ACI)	Unit 1 ACI Silo	0.043	0.043	0.043
EP-02(ACI)	Unit 2 ACI Silo	0.043	0.043	0.043
EP-03A(ACI)	Carbon Silo Weight Feeders	0.0086	0.0086	0.0086
EP-04A(ACI)	Carbon Silo Weight Feeders	0.0086	0.0086	0.0086
EP-01(DFA)	Baghouse Separator 1A Exhauster	0.21	0.21	0.21
EP-02(DFA)	Baghouse Separator 1B Exhauster	0.21	0.21	0.21
EP-03(DFA)	Baghouse Separator 2A Exhauster	0.21	0.21	0.21
EP-04(DFA)	Baghouse Separator 2B Exhauster	0.21	0.21	0.21
EP-05(DFA)	Spare Baghouse Separator Exhauster	0.21	0.21	0.21
EP-06(DFA)	Ash Silo #1	0.21	0.21	0.21
EP-02(FIX)	Lime Silo	0.103	0.103	0.103

Compliance with these limits, shall limit the potential to emit of PM, PM<sub>10</sub>, and PM<sub>2.5</sub> to less than 25 tons per twelve (12) consecutive month period, PM<sub>10</sub> emissions are less than 15 tons per year, PM<sub>2.5</sub> emissions are less than 10 tons per year shall render the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)) not applicable to the 2012 Modification permitted under SSM No. 165-32045-00001 and as modified in 2013 under SSM No. 165-33709-00001, issued November 27, 2013.

**326 IAC 2-4.1 (Major Sources of Hazardous Air Pollutants (HAP))**

The provisions of 326 IAC 2-4.1 apply to any owner or operator who constructs or reconstructs a major source of hazardous air pollutants (HAP), as defined in 40 CFR 63.41, after July 27, 1997, unless the

major source has been specifically regulated under or exempted from regulation under a NESHAP that was issued pursuant to Section 112(d), 112(h), or 112(j) of the Clean Air Act (CAA) and incorporated under 40 CFR 63. On and after June 29, 1998, 326 IAC 2-4.1 is intended to implement the requirements of Section 112(g)(2)(B) of the Clean Air Act (CAA).

The operation of this source will emit equal to or greater than ten (10) tons per year for a single HAP and equal to or greater than twenty-five (25) tons per year for a combination of HAPs. Therefore, 326 IAC 2-4.1 would apply to this source. However, pursuant to 326 IAC 2-4.1-1(b)(2), because this source is specifically regulated under NESHAP 40 CFR 63, Subpart UUUUU, which was issued pursuant to Section 112(d), 112(h), or 112(j) of the CAA, this source is exempt from the requirements of 326 IAC 2-4.1.

### **326 IAC 2-6 (Emission Reporting)**

This source is subject to the requirements of 326 IAC 2-6 (Emission Reporting), since it has the potential to emit NO<sub>x</sub> and SO<sub>2</sub> equal to or greater than two thousand five hundred (2,500) tons per year and has the potential to emit PM<sub>10</sub> equal to or greater than two hundred fifty (250) tons per year. Pursuant to 326 IAC 2-6-3(a)(1), the Permittee shall submit annually, by July 1, an emission statement covering the previous calendar year. The emission statement shall contain, at a minimum, the information specified in 326 IAC 2-6-4.

### **326 IAC 2-7-6(5) (Annual Compliance Certification)**

The U.S. EPA Federal Register 79 FR 54978 notice does not exempt Title V Permittees from the requirements of 40 CFR 70.6(c)(5)(iv) or 326 IAC 2-7-6(5)(D), but the submittal of the Title V annual compliance certification to IDEM satisfies the requirement to submit the Title V annual compliance certifications to EPA. IDEM does not intend to revise any permits since the requirements of 40 CFR 70.6(c)(5)(iv) or 326 IAC 2-7-6(5)(D) still apply, but Permittees can note on their Title V annual compliance certifications that submission to IDEM has satisfied reporting to EPA per Federal Register 79 FR 54978. This only applies to Title V Permittees and Title V compliance certifications.

### **326 IAC 5-1 (Opacity Limitations)**

This source is subject to the opacity limitations specified in 326 IAC 5-1-2(1)

### **326 IAC 6-4 (Fugitive Dust Emissions Limitations)**

The source is subject to the requirements of 326 IAC 6-4, because the paved and unpaved roads, coal handling equipment, and slag handling have the potential to emit fugitive particulate emissions. Pursuant to 326 IAC 6-4 (Fugitive Dust Emissions Limitations), the source shall not allow fugitive dust to escape beyond the property line or boundaries of the property, right-of-way, or easement on which the source is located, in a manner that would violate 326 IAC 6-4.

### **326 IAC 6-5 (Fugitive Particulate Matter Emission Limitations)**

Pursuant to 326 IAC 6-5-1(1)(a)(2) and 326 IAC 6-5-1(1)(b), this source is not subject to the requirements of IAC 6-5 because the source is not located in any secondary nonattainment areas and it has received all necessary preconstruction approvals before December 13, 1985.

### **326 IAC 6.5 (Particulate Matter Limitations Except Lake County)**

Pursuant to 326 IAC 6.5-1-1(a), this source (located in Vermillion County) is not subject to the requirements of 326 IAC 6.5 because it is not located in one of the following counties: Clark, Dearborn, Dubois, Howard, Marion, St. Joseph, Vanderburgh, Vigo or Wayne.

### **326 IAC 6.8 (Particulate Matter Limitations for Lake County)**

Pursuant to 326 IAC 6.8-1-1(a), this source (located in Vermillion County) is not subject to the requirements of 326 IAC 6.8 because it is not located in Lake County.

### **326 IAC 21 (Acid Deposition Control)**

326 IAC 21 incorporates by reference the provisions of 40 CFR 72 through 40 CFR 78 for the purposes of implementing an acid rain program that meets the requirements of Title IV of the Clean Air Act and to incorporate monitoring, record keeping, and reporting requirements for nitrogen oxide and sulfur dioxide emissions to demonstrate compliance with nitrogen oxides and sulfur dioxide emission reduction requirements. This source is subject to the requirements of 326 IAC 21.



### 326 IAC 24 (Cross-State Air Pollutant Rule (CSAPR) Programs)

See the Cross-State Air Pollutant Rule (CSAPR) section above.

<b>State Rule Applicability – Individual Facilities</b>
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State rule applicability has been reviewed as follows:

#### Boilers No. 1 and 2

#### **326 IAC 3-5 (Continuous Emissions Monitoring)**

Pursuant to 326 IAC 3-5-1(a)(1), Boilers No. 1 and 2, are subject to the monitoring requirements of 326 IAC 3-5 because the emission units are required to perform continuous monitoring under 326 IAC 12.

#### **326 IAC 6-2-3 (Particulate Matter Emissions Limitations for Sources of Indirect Heating)**

Pursuant to 326 IAC 6-2-1(c), for Boilers No. 1 and 2 are existing and in operation, or received permit to construct, prior to September 21, 1983 and not located in Lake, Porter, Marion, Boone, Hamilton, Hendricks, Johnson, Morgan, Shelby, or Hancock Counties are subject to the requirements of 326 IAC 6-2-3. Pursuant to 326 IAC 6-2-3 (Particulate Matter Emissions Limitations for Sources of Indirect Heating), the PM emissions from Boilers No. 1 and 2 shall each be limited to 0.227 pounds per million Btu heat input based on each boiler having a heat input capacity of 4802 million Btu per hour. These limitations will satisfy the requirement to maintain PM emissions below the amounts assumed in the PSD modeling analysis that was performed for the turbines. The limitation was calculated using the following equation:

$$Pt = \frac{C \times a \times h}{76.5 \times Q^{0.75} \times N^{0.25}}$$

Where:

- Pt = Pounds of particulate matter emitted per million British thermal units (lb/MMBtu).
- Q = Total source maximum operating capacity rating in MMBtu/hr heat input. The maximum operating capacity rating is defined as the maximum capacity at which the facility is operated or the nameplate capacity, whichever is specified in the facility's permit application, except when some lower capacity is contained in the facility's operation permit; in which case, the capacity specified in the operation permit shall be used = 9,604 MMBtu/hr (capacity of Boilers 1-2).
- C = Maximum ground level concentration with respect to distance from the point source at the "critical" wind speed for level terrain. This shall equal fifty (50) micrograms per cubic meter for a period not to exceed a sixty (60) minute time period.
- a = Plume rise factor which is used to make allowance for less than theoretical plume rise. The value sixty-seven tenths (0.67) shall be used for Q less than or equal to one thousand (1,000) million British thermal units per hour heat input = 0.8.
- N = Number of stacks in fuel burning operation = 2.
- h = Stack height in feet. If a number of stacks of different heights exist, the average stack height to represent stacks shall be calculated by weighing each stack height with its particulate matter emission rate as follows: = 500 feet.

$$h = \frac{\sum_{i=1}^N H_i \times pa_i \times Q}{\sum_{i=1}^N pa_i \times Q}$$

Where:

- $H_i$  = height of facility  $i$  stack, ft.  
 $pa_i$  = actual controlled emission rate of facility  $i$ , (lb/MMBtu), using an emission factor from AP-42 or stack test data. Stacks constructed after January 1, 1971, shall be credited with GEP stack height only. GEP stack height shall be calculated as specified in 326 IAC 1-7.  
 $Q$  = Heat input capacity of facility  $i$ , MMBtu/hr

### **326 IAC 7-4-8 (Vermillion County Sulfur dioxide emission limitations)**

Pursuant to 326 IAC 7-4-8 (Vermillion County Sulfur Dioxide Emission Limitations), the SO<sub>2</sub> emissions from Boiler No. 1 and Boiler No. 2 shall not exceed 4.40 pounds per million Btu lbs/MMBtu), demonstrated using a thirty (30) day rolling average. This limitation will ensure that SO<sub>2</sub> emissions do not exceed the amount assumed in the modeling analysis performed for the Vermillion County SO<sub>2</sub> SIP limits.

### **326 IAC 8-1-6 (VOC Rules: General Reduction Requirements for New Facilities)**

Boilers No. 1 and 2 are not subject to the requirements of 326 IAC 8-1-6 because it was constructed before January 1, 1980

### **326 IAC 9-1 (Carbon Monoxide Emission Limits)**

The requirements of 326 IAC 9-1 do not apply to the Boilers No. 1 and 2, because this source does not operate a catalyst regeneration petroleum cracking system or a petroleum fluid coker, grey iron cupola, blast furnace, basic oxygen steel furnace, or other ferrous metal smelting equipment.

### **326 IAC 10-2 (NO<sub>x</sub> Emissions from Large Affected Units)**

Pursuant to 326 IAC 10-2-1(a)(1), the natural gas-fired Boiler No. 1 and Boiler No. 2 is not subject to the requirements of 326 IAC 10-2 because it is subject to the CSAPR NO<sub>x</sub> Ozone Season Group 3 Trading Program established under 40 CFR 97, Subpart GGGGG.

### Auxiliary Boiler

### **326 IAC 6-2-3 (Particulate Matter Emission Limitations for Sources of Indirect Heating)**

Pursuant to 326 IAC 6-2-1(c), for Auxiliary Boiler existing and in operation, or received permit to construct, prior to September 21, 1983 and not located in Lake, Porter, Marion, Boone, Hamilton, Hendricks, Johnson, Morgan, Shelby, or Hancock Counties are subject to the requirements of 326 IAC 6-2-3. Pursuant to 326 IAC 6-2-3 (Particulate Emission Limitations for Sources of Indirect Heating: Emission limitations for facilities specified in 326 IAC 6-2-1(c), the PM emissions from the Auxiliary Boiler stack shall not exceed 0.233 pound per million Btu heat input (lbs/MMBtu). This limitation was calculated using the following equation:

$$Pt = \frac{C \times a \times h}{76.5 \times Q^{0.75} \times N^{0.25}}$$

Where:

- $Pt$  = Pounds of particulate matter emitted per million British thermal units (lb/MMBtu).  
 $Q$  = Total source maximum operating capacity rating in MMBtu/hr heat input. The maximum operating capacity rating is defined as the maximum capacity at which the facility is operated or the nameplate capacity, whichever is specified in the facility's permit application, except when some lower capacity is contained in the facility's operation permit; in which case, the capacity specified in the operation permit shall be used= 9,677 MMBtu/hr (capacity of Boilers 1-2 and Auxiliary).  
 $C$  = Maximum ground level concentration with respect to distance from the point source at the "critical" wind speed for level terrain. This shall equal fifty (50) micrograms per cubic meter for a period not to exceed a sixty (60) minute time period.

a = Plume rise factor which is used to make allowance for less than theoretical plume rise. The value sixty-seven tenths (0.67) shall be used for Q less than or equal to one thousand (1,000) million British thermal units per hour heat input = 0.8.

N = Number of stacks in fuel burning operation = 3.

h = Stack height in feet. If a number of stacks of different heights exist, the average stack height to represent stacks shall be calculated by weighing each stack height with its particulate matter emission rate as follows: = 573.7 feet.

$$h = \frac{\sum_{i=1}^N H_i \times pa_i \times Q}{\sum_{i=1}^N pa_i \times Q}$$

Where:

H<sub>i</sub> = height of facility i stack, ft.

pa<sub>i</sub> = actual controlled emission rate of facility i, (lb/MMBtu), using an emission factor from AP-42 or stack test data. Stacks constructed after January 1, 1971, shall be credited with GEP stack height only. GEP stack height shall be calculated as specified in 326 IAC 1-7.

Q = Heat input capacity of facility i, MMBtu/hr

### **326 IAC 7-1.1 Sulfur Dioxide Emission Limitations**

This auxiliary boiler is not subject to 326 IAC 326 IAC 7-1.1 because it has a potential to emit (or limited potential to emit) sulfur dioxide (SO<sub>2</sub>) of less than 25 tons per year or 10 pounds per hour.

### **326 IAC 8-1-6 (VOC Rules: General Reduction Requirements for New Facilities)**

The Auxiliary Boiler is not subject to the requirements of 326 IAC 8-1-6 because it was constructed before January 1, 1980.

### **326 IAC 9-1 (Carbon Monoxide Emission Limits)**

The requirements of 326 IAC 9-1 do not apply to the Auxiliary Boiler, because this source does not operate a catalyst regeneration petroleum cracking system or a petroleum fluid coker, grey iron cupola, blast furnace, basic oxygen steel furnace, or other ferrous metal smelting equipment.

### **326 IAC 10-3 (Nitrogen Oxide Reduction Program for Specific Source Categories)**

The requirements of 326 IAC 10-3 do not apply to the Auxiliary Boiler, since this unit is not a blast furnace gas-fired boiler, a Portland cement kiln, or a facility specifically listed under 326 IAC 10-3-1(a)(2).

### Coal processing drop points, coal scale exhausts, and coal bunkers

### **326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes)**

Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes), the particulate emission rate from the coal processing drop points, coal scale exhausts, and coal bunkers shall not exceed 86.19 pounds per hour when operating at a process weight rate of 1900 tons per hour. This is determined by the following equation:

Interpolation and extrapolation of the data for the process weight rate in excess of sixty thousand (60,000) pounds per hour shall be accomplished by use of the equation:

$$E = 55.0 P^{0.11} - 40$$

Where:

E = rate of emission in pounds per hour: and

P = process weight rate in tons per hour

Pursuant to 326 IAC 6-3-2(e)(3), when the process weight exceeds two hundred (200) tons/hour, the maximum allowable emission may exceed 86.19 pounds per hour, provided the concentration of

particulate matter in the discharge gases to the atmosphere is less than 0.10 pounds per one thousand (1,000) pounds of gases.

*limestone handling and storage system, and the gypsum conveying system*

**326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes)**

Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes), particulate emissions from the following emission units at the limestone handling and storage system, and the gypsum conveying system shall not exceed the emission limits listed in the table below while operating at the maximum throughput rate:

Unit Description	Max. Throughput Rate (tons/hr)	Particulate Emission Limit (lbs/hr)
Railcar/Truck Unloading Operation	1,000	77.6
Each of the Hoppers	500	69.0
Each of the Belt Feeders (LHBF-1 and LHBF-2)	500	69.0
Each of the Reclaim Hoppers	200	58.5
Each of the Belt Feeders (LHBF-3 and LHBF-4)	200	58.5
Gypsum Conveying System	150	55.4

The limitations for these facilities were calculated using the following equations. Interpolation and extrapolation of the data for the process weight rate in excess of sixty thousand (60,000) pounds per hour shall be accomplished by use of the equation:

$$E = 55.0 P^{0.11} - 40$$

Where:

E = rate of emission in pounds per hour and  
 P = process weight rate in tons per hour

Pursuant to 326 IAC 6-3-2(e)(3), when the process weight exceeds 200 tons per hour, the maximum allowable emission may exceed that shown in this table, provided the concentration of particulate matter in the gas discharged to the atmosphere is less than 0.10 pounds per 1,000 pounds of gases.

*Sorbent Silos, Lime Silo, Limestone Silo, Activated Carbon Silos*

**326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes)**

Pursuant to 326 IAC 6-3-1(a), the requirements of 326 IAC 6-3-2 are applicable to the Lime Silo (1) Limestone Silo and (2) Activated Carbon Silos, since it is a manufacturing process not exempted from this rule under 326 IAC 6-3-1(b) and is not subject to a particulate matter limitation that is as stringent as or more stringent than the particulate limitation established in this rule as specified in 326 IAC 6-3-1(c).

Pursuant to 326 IAC 6-3-2, the particulate matter (PM) from the Lime Silo (1) Limestone Silo and (2) Activated Carbon Silos shall not exceed 30.5 pounds per hour each when operating at a process weight rate of 20 tons per hour. The pound per hour limitation was calculated with the following equation:

$$E = 4.1 P^{0.67}$$

Where:

E = rate of emission in pounds per hour and  
 P = process weight rate in tons per hour

Summary of Process Weight Rate Limits		
Process / Emission Unit	P (ton/hr)	E (lb/hr)

Summary of Process Weight Rate Limits		
Process / Emission Unit	P (ton/hr)	E (lb/hr)
Sorbent Silos, Lime Silo, Limestone Silo, Activated Carbon Silos	20	30.5

The Bin Vent Filter shall be in operation at all times the Sorbent Silos, Lime Silo, Limestone Silo, Activated Carbon Silos are in operation, in order to comply with this limit.

Limestone Surge Bin

**326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes)**

Pursuant to 326 IAC 6-3-1(a), the requirements of 326 IAC 6-3-2 are applicable to the Limestone Surge Bin, since it is a manufacturing process not exempted from this rule under 326 IAC 6-3-1(b) and is not subject to a particulate matter limitation that is as stringent as or more stringent than the particulate limitation established in this rule as specified in 326 IAC 6-3-1(c).

Pursuant to 326 IAC 6-3-2, the particulate matter (PM) from the Limestone Surge Bin shall not exceed 40.0 pounds per hour when operating at a process weight rate of 30 tons per hour each. The pound per hour limitation was calculated with the following equation:

$$E = 4.1 P^{0.67}$$

Where:

E = rate of emission in pounds per hour and  
 P = process weight rate in tons per hour

Summary of Process Weight Rate Limits		
Process / Emission Unit	P (ton/hr)	E (lb/hr)
Limestone Surge Bin	30	40

The Bin Vent Filter shall be in operation at all times the Limestone Surge Bin is in operation, in order to comply with this limit.

Exhausters

**326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes)**

Pursuant to 326 IAC 6-3-1(a), the requirements of 326 IAC 6-3-2 are applicable to the Exhausters, since it is a manufacturing process not exempted from this rule under 326 IAC 6-3-1(b) and is not subject to a particulate matter limitation that is as stringent as or more stringent than the particulate limitation established in this rule as specified in 326 IAC 6-3-1(c).

Pursuant to 326 IAC 6-3-2, the particulate matter (PM) from (5) Exhausters shall not exceed 45.4 pounds per hour each when operating at a process weight rate of 54.4 tons per hour. The pound per hour limitation was calculated with the following equation:

$$E = 55.0 P^{0.11} - 40$$

Where:

E = rate of emission in pounds per hour and  
 P = process weight rate in tons per hour

Summary of Process Weight Rate Limits		
Process / Emission Unit	P (ton/hr)	E (lb/hr)

Summary of Process Weight Rate Limits		
Process / Emission Unit	P (ton/hr)	E (lb/hr)
Five (5) Exhausters	54.4	45.4

The Baghouse shall be in operation at all times the five (5) Exhausters are in operation, in order to comply with this limit.

Ash Silo

**326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes)**

Pursuant to 326 IAC 6-3-1(a), the requirements of 326 IAC 6-3-2 are applicable to the Ash Silo, since it is a manufacturing process not exempted from this rule under 326 IAC 6-3-1(b) and is not subject to a particulate matter limitation that is as stringent as or more stringent than the particulate limitation established in this rule as specified in 326 IAC 6-3-1(c).

Pursuant to 326 IAC 6-3-2, the particulate matter (PM) from the ash silo shall not exceed 47.8 pounds per hour when operating at a process weight rate of 70 tons per hour. The pound per hour limitation was calculated with the following equation:

$$E = 55.0 P^{0.11} - 40$$

Where:

E = rate of emission in pounds per hour and  
 P = process weight rate in tons per hour

Summary of Process Weight Rate Limits		
Process / Emission Unit	P (ton/hr)	E (lb/hr)
Ash Silo	70	47.8

The Bin Vent Filter shall be in operation at all times the Ash Silos in operation, in order to comply with this limit.

Generators identified as 3A, 3B, 3C, and 3D

**326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes)**

Pursuant to 326 IAC 1-2-59, liquid and gaseous fuels are not considered as part of the process weight, therefore the requirements of 326 IAC 6-3 do not apply to the generators.

**326 IAC 7-1.1 (Sulfur Dioxide Emission Limitations)**

These generators are not subject to 326 IAC 326 IAC 7-1.1 because the generators have a potential to emit (or limited potential to emit) sulfur dioxide (SO<sub>2</sub>) of less than 25 tons per year or 10 pounds per hour.

**326 IAC 8-1-6 (VOC Rules: General Reduction Requirements for New Facilities)**

Even though, the generators, were constructed after January 1, 1980, it is not subject to the requirements of 326 IAC 8-1-6 because its unlimited VOC potential emissions are less than twenty-five (25) tons per year.

**326 IAC 9-1 (Carbon Monoxide Emission Limits)**

The requirements of 326 IAC 9-1 do not apply to the generators, because this source does not operate a catalyst regeneration petroleum cracking system or a petroleum fluid coker, grey iron cupola, blast furnace, basic oxygen steel furnace, or other ferrous metal smelting equipment.

Degreasing Operations

**326 IAC 8-3-2 (Cold Cleaner Operations)**

The degreasing operations are subject to 326 IAC 8-3-2 (Cold Cleaner Operations). This rule applies to cold cleaner type degreasing facilities constructed after July 1, 1990.

**326 IAC 8-3-8 (Material requirements for cold cleaning degreasers)**

The degreasing operations are subject to the provisions of 326 IAC 8-3-8 (Material requirements for cold cleaning degreasers) because the source is a user of solvents for use in cold cleaning degreasers. The source shall meet the material requirements for cold cleaning degreasers specified in 326 IAC 8-3-8(c) and record keeping requirements specified in 326 IAC 8-3-8(d) of this rule.

Emergency Engines identified as ENG-01, ENG-02, ENG-03, ENG-04, ENG-05

**326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes)**

Pursuant to 326 IAC 1-2-59, liquid and gaseous fuels are not considered as part of the process weight, therefore the requirements of 326 IAC 6-3 do not apply to the emergency engines.

**326 IAC 7-1.1 (Sulfur Dioxide Emission Limitations)**

These emergency engines are not subject to 326 IAC 7-1.1 because these units have potential to emit (or limited potential to emit) sulfur dioxide (SO<sub>2</sub>) of less than 25 tons per year or 10 pounds per hour.

**326 IAC 8-1-6 (VOC Rules: General Reduction Requirements for New Facilities)**

Even though, the emergency engines, were constructed after January 1, 1980, these units are not subject to the requirements of 326 IAC 8-1-6 because its unlimited VOC potential emissions are less than twenty-five (25) tons per year.

**326 IAC 9-1 (Carbon Monoxide Emission Limits)**

The requirements of 326 IAC 9-1 do not apply to the emergency engines, because this source does not operate a catalyst regeneration petroleum cracking system or a petroleum fluid coker, grey iron cupola, blast furnace, basic oxygen steel furnace, or other ferrous metal smelting equipment.

**Compliance Determination and Monitoring Requirements**

Permits issued under 326 IAC 2-7 are required to assure that sources can demonstrate compliance with all applicable state and federal rules on a continuous basis. All state and federal rules contain compliance provisions, however, these provisions do not always fulfill the requirement for a continuous demonstration. When this occurs, IDEM, OAQ, in conjunction with the source, must develop specific conditions to satisfy 326 IAC 2-7-5. As a result, Compliance Determination Requirements are included in the permit. The Compliance Determination Requirements in Section D of the permit are those conditions that are found directly within state and federal rules and the violation of which serves as grounds for enforcement action.

If the Compliance Determination Requirements are not sufficient to demonstrate continuous compliance, they will be supplemented with Compliance Monitoring Requirements, also in Section D of the permit. Unlike Compliance Determination Requirements, failure to meet Compliance Monitoring conditions would serve as a trigger for corrective actions and not grounds for enforcement action. However, a violation in relation to a compliance monitoring condition will arise through a source's failure to take the appropriate corrective actions within a specific time period.

(a) The Compliance Determination Requirements applicable to this source are as follows:

Testing Requirements:

Summary of Testing Requirements					
Emission Unit	Control Device	Timeframe for Testing or Date of Last Valid Demonstration)	Pollutant	Frequency of Testing	Requirements

Two (2) of the Five (5) separator/exhausters, identified as emissions point EP-01(DFA), EP-02(DFA), EP-03(DFA), EP-04(DFA) and EP-05 (DFA)	Baghouse	The separator/exhauster tested shall be the unit in which the longest amount of time has elapsed since its previous test	PM, PM <sub>10</sub> and PM <sub>2.5</sub>	Every five years	326 IAC 2-2
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Continuous Emissions Monitoring System (CEMS) and Continuous Opacity Monitoring (COM) Requirements:

Emission Unit	Type of Continuous Monitor (Pollutant Monitored)	Applicable Rule or Authority
Boiler #1	CEMS (PM, SO <sub>2</sub> , NO <sub>x</sub> , and Hg)	326 IAC 3-5 40 CFR 63 NESHAP UUUUU
Boiler #2		

(b) The Compliance Monitoring Requirements applicable to this source are as follows:

Facilities	Control	Parameter	Frequency	Range/ Value	Excursions and Exceedances	Limits or requirements
Boilers 1 and 2	Electrostatic Precipitator (ESP)	T-R sets in service and T-R electrical values of Primary and secondary voltages and Current.	Daily when CEMS are down for more than 24 hours.	> 90% T-R sets in service	Response Steps	326 IAC 6-2-3
Boilers 1 and 2	Flue Gas Desulfurization (FGD)	Boiler load, recirculation pH, Slurry feed rate and number of recirculation pumps	Twice per day when CEMS are down for more than 24 hours day	4.40 lb/mmBtu for 30 day rolling weighted average	Response Steps	326 IAC 7-4-8
		SO <sub>2</sub> CEMS	Continuous	< 25% for 3 consecutive s 6 minute intervals		
Boilers 1 and 2	NA	Opacity COM	Continuous	< 25% for 3 consecutive s 6 minute intervals	Response Steps	326 IAC 5-1-3
Auxiliary Boiler	Opacity rule	Visible Emissions	Daily	Normal / Abnormal	Response Steps	326 IAC 6-2-3



Facilities	Control	Parameter	Frequency	Range/ Value	Excursions and Exceedances	Limits or requirements
Transfer points and Coal unloading station(s) doorways and drop points	NA	Visible Emissions	Weekly	Normal / Abnormal	Response Steps	326 IAC 6-3-2
Transfer points and ball mill and partially enclosed railcar limestone unloading station						
Ash storage pond area(s)						
Limestone transfer points						
Gypsum transfer points						
One (1) Limestone Silo, One (1) Limestone Surge Bin, Two (2) ACI Silos, Four (4) DSI Silos, and One (1) Lime Silo	Bin Vent Filter	Visible Emissions	Weekly	Normal-Abnormal	Response Steps	326 IAC 2-2 and 40 CFR 64
Five (5) baghouse separator exhausters	Baghouse	Water Pressure Drop	Weekly	1.0 to 6.0 inches		
		Visible Emissions		Normal-Abnormal		
ash silo	Bin Vent Filter	Visible Emissions	Weekly	Normal-Abnormal		
Fixated Material Storage Pile	Wetting	Visible Emissions	Weekly	Normal-Abnormal		

**Proposed Changes**

As part of this permit approval, the permit may contain new or different permit conditions and some conditions from previously issued permits/approvals may have been corrected, changed, or removed. These corrections, changes, and removals may include Title I changes.

The following changes were made to conditions contained previously issued permits/approvals (these changes may include Title I changes):

- (1) The permit is revised to include the most recent version of 40 CFR 60 Subpart JJJJ, 40 CFR 60 Subpart IIII, and 40 CFR 63 Subpart ZZZZ as permit Attachment G, C, and D respectively, but these changes are not shown in bold and strikethrough text in this TSD.
- (2) Revised Section A.4 and E.6.2 to include the unit description for ENG-05, correcting unit IDs, and correct federal rule applicable to NSPS subpart JJJJ rule citations.
- (3) Removed the content of Section D.3 as the generators are not subject to 326 IAC 7-1.1-1 and Visual Emissions are not required due to the use of ultra low sulfur diesel lowering the potential emissions of sulfur dioxide (SO<sub>2</sub>) to be less than 25 tons per year.

- (4) Revised Section D.6 as the Auxiliary Boiler is no longer subject to 436 IAC 7-1.1-1 due to the use of ultra low sulfur diesel lowering the potential emissions of sulfur dioxide (SO<sub>2</sub>) to be less than 25 tons per year.
- (5) Revised Section E.1 NESHAP subpart ZZZZ to correct federal rule applicability for ENG-01 and ENG-02.
- (6) Revised Section E.2.2 NSPS subpart OOO to correct federal rule applicability for limestone handling operation.
- (7) Revised Section E.5 NESHAP subpart ZZZZ to correct federal rule applicability for engines 3A-3D, ENG-02, and ENG-03 and to include emission units ENG-01, ENG-04 and ENG-05.
- (8) Section G has been updated to reflect that the source is now subject to the requirements of the TR NO<sub>x</sub> Ozone Season Group 3 Trading program.

### **Conclusion and Recommendation**

Unless otherwise stated, information used in this review was derived from the application and additional information submitted by the applicant. An application for the purposes of this review was received on September 29, 2023.

The operation of this stationary electric utility generating station shall be subject to the conditions of the attached proposed Part 70 Operating Permit Renewal No. 165-47094-00001.

The staff recommends to the Commissioner that the Part 70 Operating Permit Renewal be approved.

### **IDEM Contact**

- (a) If you have any questions regarding this permit, please contact Christopher Chin, Indiana Department Environmental Management, Office of Air Quality, Permits Branch, 100 North Senate Avenue, MC 61-53 IGCN 1003, Indianapolis, Indiana 46204-2251, or by telephone at (317) 234-7434 or (800) 451-6027, and ask for Christopher Chin.
- (b) A copy of the findings is available on the Internet at: <http://www.in.gov/ai/appfiles/idem-caats/>
- (c) For additional information about air permits and how the public and interested parties can participate, refer to the IDEM Air Permits page on the Internet at: <https://www.in.gov/idem/airpermit/public-participation/>; and the Citizens' Guide to IDEM on the Internet at: <https://www.in.gov/idem/resources/citizens-guide-to-idem/>.

**Appendix A: Emissions Calculations  
Summary**

**Company Name:** Duke Energy Indiana, LLC - Cayuga Generating Station  
**Address City IN Zip:** 3300 N SR 63, Cayuga, Indiana 47928  
**Permit Number:** 165-47094-00001  
**Reviewer:** Christopher Chin

Uncontrolled Potential To Emit									
Point ID	PM (tons/yr)	PM <sub>10</sub> (tons/yr)	PM <sub>2.5</sub> (tons/yr)	SO <sub>2</sub> (tons/yr)	VOC (tons/yr)	CO (tons/yr)	NOx (tons/yr)	Combined HAPs (tons/yr)	Individual HAPs HCL (tons/yr)
Boiler 1	78,997.68	24,479.29	11,049.689	123,828.86	59.25	493.74	14,812.07	17,455.525	1,184.97
Boiler 2	78,997.68	24,479.29	11,049.689	123,828.86	59.25	493.74	14,812.07	17,455.525	1,184.97
Aux Boiler	4.56	5.24	3.530	4.75	0.57	11.39	45.55	0.013	
Non-emergency Engine 3A	8.15	7.53	7.306	1.95	11.83	111.69	420.48	0.20	
Non-emergency Engine 3B	8.15	7.53	7.31	1.95	11.83	111.69	420.48	0.20	
Non-emergency Engine 3C	8.15	7.53	7.31	1.95	11.83	111.69	420.48	0.20	
Non-emergency Engine 3D	8.15	7.53	7.31	1.95	11.83	111.69	420.48	0.20	
Coal Handling	12.73	6.02	0.912						
FGD Limestone Handling	71.39	26.46	26.455						
Dry Sorbent Silos	14.74	14.74	14.736						
Fixation	23.97	8.27	6.46						
Limestone for AS Mitigation	51.61	51.54	51.54						
Dry Flyash Handling	469.29	469.29	469.29						
Unload Wet FA into Truck, Unload Truck	7.70	3.64	0.55						
Storage Piles Wind Erosion	8.80	4.40	0.66						
Heavy Equipment on Pile	53.13	14.34	1.43						
Roadway	55.53	11.11	2.73						
Emergency Engine 1 Insignificant Activity	0.09	0.09	0.09	0.08	0.10	0.26	1.22	0.00	
Emergency Engine 2 Insignificant Activity	0.12	0.07	0.069	0.72	0.13	0.98	4.28	0.98	
Emergency Engine 3 Insignificant Activity	0.08	0.30	0.08	0.00	0.00	0.00	0.00	0.59	
Emergency Engine 4 Insignificant Activity	0.01	0.05	0.01	0.00	0.00	0.00	0.00	0.09	
Emergency Engine 5 Insignificant Activity	0.00	0.01	0.01	0.00	0.01	1.62	0.96	0.01	
<b>Total Emissions</b>	<b>158,801.70</b>	<b>49,604.26</b>	<b>22,707.14</b>	<b>247,671.09</b>	<b>166.61</b>	<b>1,448.48</b>	<b>31,358.06</b>	<b>34,913.53</b>	<b>2,369.93</b>

Limited Potential To Emit									
Point ID	PM (tons/yr)	PM <sub>10</sub> (tons/yr)	PM <sub>2.5</sub> (tons/yr)	SO <sub>2</sub> (tons/yr)	VOC (tons/yr)	CO (tons/yr)	NOx (tons/yr)	Combined HAPs (tons/yr)	Individual HAPs HCL (tons/yr)
Boiler 1	630.98	1051.64	1051.64	4206.55	59.25	493.74	9464.74	50.30	42.07
Boiler 2	630.98	1051.64	1051.64	4953.15	59.25	493.74	9464.74	50.30	42.07
Aux Boiler	0.46	0.52	0.35	0.48	0.06	1.14	4.56	0.00	
Non-emergency Engine 3A	8.15	7.53	7.31	1.95	3.55	33.51	420.48	0.06	
Non-emergency Engine 3B	8.15	7.53	7.31	1.95	3.55	33.51	420.48	0.06	
Non-emergency Engine 3C	8.15	7.53	7.31	1.95	3.55	33.51	420.48	0.06	
Non-emergency Engine 3D	8.15	7.53	7.31	1.95	3.55	33.51	420.48	0.06	
Coal Handling	5.49	2.59	0.39						
FGD Limestone Handling	3.82	1.41	1.41						
Dry Sorbent Silos	0.15	0.15	0.15						
Fixation	0.45	0.24	0.09						
Limestone for AS Mitigation	0.53	0.52	0.52						
Dry Flyash Handling	4.87	4.78	4.71						
Storage Piles Wind Erosion	8.80	4.40	0.66						
Heavy Equipment on Pile	13.47	3.64							
Roadway	5.55	1.11	0.27						
Emergency Engine 1 Insignificant Activity	0.09	0.09	0.09	0.08	0.10	0.26	1.22	0.00	
Emergency Engine 2 Insignificant Activity	0.12	0.07	0.07	0.72	0.13	0.98	4.28	0.98	
Emergency Engine 3 Insignificant Activity	0.08	0.30	0.08	0.00	0.00	0.00	0.00	0.59	
Emergency Engine 4 Insignificant Activity	0.01	0.05	0.01	0.00	0.00	0.00	0.00	0.09	
Emergency Engine 5 Insignificant Activity	0.00	0.01	0.01	0.00	0.01	1.62	0.96	0.01	0.00
<b>Total Emissions</b>	<b>1338.43</b>	<b>2153.26</b>	<b>2141.30</b>	<b>9168.79</b>	<b>132.98</b>	<b>1125.50</b>	<b>20622.41</b>	<b>102.51</b>	<b>84.13</b>

**Appendix A: Emission Calculations  
ATP Summary**

**Company Name:** Duke Energy Indiana, LLC - Cayuga Generating Station  
**Source Address:** 3300 N SR 63, Cayuga, Indiana 47928  
**Permit Number:** 165-47094-00001  
**Reviewer:** Christopher Chin

**1. New Emissions Units**

New Emissions Units (ton/yr)								
Process/Emission Unit	PM	PM <sub>10</sub>	PM <sub>2.5</sub>	SO <sub>2</sub>	NO <sub>x</sub>	VOC	CO	(Pb, Be, Hg, etc.)
ENG-5	4.1E-03	8.4E-03	8.4E-03	2.6E-04	9.6E-01	1.3E-02	1.6E+00	8.92E-03
<b>Significant Levels</b>	<b>25</b>	<b>15</b>	<b>10</b>	<b>40</b>	<b>40</b>	<b>40</b>	<b>100</b>	<b>Formaldehyde</b>

**Appendix A: Emissions Calculations  
Boiler #1 Emissions**

**Company Name: Duke Energy Indiana, LLC - Cayuga Generating Station**  
**Address City IN Zip: 3300 N SR 63, Cayuga, Indiana 47928**  
**Permit Number: 165-47094-00001**  
**Reviewer: Christopher Chin**

Emissions Unit	Boiler #1	Sulfur Content	3.3%
Commercial Date	1970	Ash Content	10%
Boiler Type	T-Fired		
Heat Input Capacity	4802 MMBtu/hr	Device	Control Eff %
Heat Content of Coal <sup>(1)</sup>	10650 Btu/lb of Coal	PM Control Eff	ESP 0.99%
Firing Rate <sup>(2)</sup>	225.45 tons/hr	SO <sub>2</sub> Confftrol E	FGD 0.96%
Potential Throughput <sup>(3)</sup>	1974942.00 tons/year	NO <sub>x</sub> Control Eff	SCR 0.50%

Fuel Oil is used for startup and flame stabilization

Compound Categories	Uncontrolled PTE					Controlled				
	Emission Factor		Reference <sup>(4)</sup>	lbs/hr	tons/yr	Emissions Factor		Reference	lbs/hr	tons/yr
	Value	Units				Value	Units			
<b>Criteria Compounds:</b>										
PM	80	lb/ton	AP-42 Table 1.1-6	18,036.00	78,997.68	0.03	lbs/MMBtu	NESHAP Limit <sup>(7)</sup>	144.06	631.0
PM (condensable)	0.30	lbs/MMBtu	AP-42 Table 1.1-5	1,440.60	6,309.83	0.02	lbs/MMBtu	AP-42 Table 1.1-5	96.04	420.7
PM-10 (filterable)	18.40	lb/ton	AP-42 Table 1.1-6	4,148.28	18,169.47	0.03	lbs/MMBtu	NESHAP Limit <sup>(7)</sup>	144.06	631.0
PM-2.5 (filterable)	4.80	lb/ton	AP-42 Table 1.1-6	1,082.16	4,739.86	0.03	lbs/MMBtu	NESHAP Limit <sup>(7)</sup>	144.06	631.0
SO2	125.40	lb/ton	AP-42 Table 1.1-3	28,271.43	123,828.86	0.20	lbs/MMBtu	NESHAP Limit <sup>(7)</sup>	960.4	4206.6
NOX	15.00	lb/ton	AP-42 Table 1.1-3	3,381.75	14,812.07	0.45	lbs/MMBtu	Acid Rain NOx	2160.9	9464.7
VOC (NMOC)	0.06	lb/ton	AP-42 Table 1.1-19	13.53	59.25	0.07	lb/ton	AP-42 Table 1.1-19	13.5	59.2
CO	0.50	lb/ton	AP-42 Table 1.1-3	112.73	493.74	0.50	lb/ton	AP-42 Table 1.1-3	112.7	493.7
HCL	1.2	lb/ton	AP-42 Table 1.1-5	270.54	1,184.97	0.002	lbs/MMBtu	NESHAP Limit <sup>(7)</sup>	9.60	42.1
HF	0.15	lb/ton	AP-42 Table 1.1-5	33.82	148.12	6.00E-05	lbs/MMBtu	NESHAP Limit <sup>(7)</sup>	0.29	1.3
Mercury	16	lbs/Tbtu	AP-42 Table 1.1-17	3,607.20	15,799.54	1.2	lbs/Tbtu	NESHAP Limit <sup>(7)</sup>	5.8E-03	2.5E-02
Benzene	0.0013	lb/ton	AP-42 Table 1.1-14 <sup>(5)</sup>	0.29	1.28	0.0013	lb/ton	AP-42 Table 1.1-14 <sup>(2)</sup>	0.29	1.28
Cyanide	0.0025	lb/ton	AP-42 Table 1.1-14 <sup>(5)</sup>	0.56	2.47	0.0025	lb/ton	AP-42 Table 1.1-14 <sup>(2)</sup>	0.56	2.47
PCDD/ PCDF	1.76E-09	lb/ton	AP-42 Table 1.1-12 <sup>(5)</sup>	4E-07	1.7E-06	1.76E-09	lb/ton	AP-42 Table 1.1-12 <sup>(2)</sup>	4E-07	1.7E-06
Selenium	0.13	lb/ton	Adj for unctr CE 95% <sup>(6)</sup>	29.31	128.37	0.0013	lb/ton	AP-42 Table 1.1-18	2.9E-01	1.3E+00
Cadmium	0.0051	lb/ton	Adj for unctr CE 95% <sup>(6)</sup>	1.15	5.04	0.000051	lb/ton	AP-42 Table 1.1-18	1.1E-02	5.0E-02
Chromium	0.026	lb/ton	Adj for unctr CE 95% <sup>(6)</sup>	5.86	25.67	0.00026	lb/ton	AP-42 Table 1.1-18	5.9E-02	2.6E-01
Manganese	0.049	lb/ton	Adj for unctr CE 95% <sup>(6)</sup>	11.05	48.39	0.00049	lb/ton	AP-42 Table 1.1-18	1.1E-01	4.8E-01
Nickel	0.028	lb/ton	Adj for unctr CE 95% <sup>(6)</sup>	6.31	27.65	0.00028	lb/ton	AP-42 Table 1.1-18	6.3E-02	2.8E-01
Beryllium	0.0021	lb/ton	Adj for unctr CE 95% <sup>(6)</sup>	4.7E-01	2.07	0.000021	lb/ton	AP-42 Table 1.1-18	4.7E-03	2.1E-02
Arsenic	0.041	lb/ton	Adj for unctr CE 95% <sup>(6)</sup>	9.24	40.49	0.00041	lb/ton	AP-42 Table 1.1-18	9.2E-02	4.0E-01
Lead	0.042	lb/ton	Adj for unctr CE 95% <sup>(6)</sup>	9.47	41.47	0.00042	lb/ton	AP-42 Table 1.1-18	9.5E-02	4.1E-01
CO2	6040	lb/ton	AP-42 Table 1.1-20	1,361,718.00	5,964,324.84	6040	lb/ton	AP-42 Table 1.1-20	1,361,718	5,964,325
CH4	0.04	lb/ton	AP-42 Table 1.1-19	9.02	39.50	0.04	lb/ton	AP-42 Table 1.1-19	9.02	39.50
N2O	0.08	lb/ton	AP-42 Table 1.1-19	18.04	79.00	0.08	lb/ton	AP-42 Table 1.1-19	18	79
			Comb HAPs		17,455.52			Comb HAPs		50.30
			Individual HAP (HCL)		15,799.54			Individual HAP (HCL)		42.1

**Methodology**

- (1) Maximum Firing Rate (ton/hr) = Heat Input (MMBtu/hr) /Heat Content (Btu/lb) x 1,000,000 x 1 ton/2000 lbs
- (2) Potential Throughput (tons/year) = max firing rate (tons/hr) x 8,760 hrs/yr
- (3) Heat Content, Sulfur Content and Sulfur Content of the Coal provided by Duke Energy
- (4) Emission Factors are from AP-42 Chapter 1.1 (Update 9/98)
- (5) AP-42 Table 1.1-12 and 1.1-14 controlled emissions, no information avialable on control efficiency.
- (6) AP-42 Table 1.1-18 controlled emissions factors divided by 0.01 to reflect uncontrolled emissions
- (7) Controled emissions based on NESHAP Subpart UUUUU

**Appendix A: Emissions Calculations  
Boiler #2 Emissions**

**Company Name: Duke Energy Indiana, LLC - Cayuga Generating Station**  
**Address City IN Zip: 3300 N SR 63, Cayuga, Indiana 47928**  
**Permit Number: 165-47094-00001**  
**Reviewer: Christopher Chin**

Emissions Unit	Boiler#2	Sulfur Content	3.3	%
Commercial Date	1970	Ash Content	10	%
Boiler Type	T-Fired			
Heat Input Capacity	4802 MMBtu/hr	Device	Control Eff %	
Heat Content of Coal <sup>(1)</sup>	10650 Btu/lb of Coal	PM Control Eff	ESP	0.99 %
Firing Rate <sup>(2)</sup>	225.45 tons/hr	SO <sub>2</sub> Conffrtrol E	FGD	0.96 %
Potential Throughput <sup>(3)</sup>	1974942.00 tons/year	NO <sub>x</sub> Control Eff	SCR	0.50 %

Fuel Oil is used for startup and flame stabilization

Compound Categories	Uncontrolled PTE					Controlled				
	Emission Factor		Reference <sup>(4)</sup>	lbs/hr	tons/yr	Emissions Factor		Reference	lbs/hr	tons/yr
	Value	Units				Value	Units			
<b>Criteria Compounds:</b>										
PM	80	lb/ton	AP-42 Table 1.1-6	18,036.00	78,997.68	0.03	lbs/MMBtu	NESHAP Limit <sup>(7)</sup>	144.06	631.0
PM (condensable)	0.30	lbs/MMBtu	AP-42 Table 1.1-5	1,440.60	6,309.83	0.02	lbs/MMBtu	AP-42 Table 1.1-5	96.04	420.7
PM-10 (filterable)	18.40	lb/ton	AP-42 Table 1.1-6	4,148.28	18,169.47	0.03	lbs/MMBtu	NESHAP Limit <sup>(7)</sup>	144.06	631.0
PM-2.5 (filterable)	4.80	lb/ton	AP-42 Table 1.1-6	1,082.16	4,739.86	0.03	lbs/MMBtu	NESHAP Limit <sup>(7)</sup>	144.06	631.0
SO <sub>2</sub>	125.40	lb/ton	AP-42 Table 1.1-3	28,271.43	123,828.86	0.20	lbs/MMBtu	NESHAP Limit <sup>(7)</sup>	1130.9	4953.2
NO <sub>x</sub>	15.00	lb/ton	AP-42 Table 1.1-3	3,381.75	14,812.07	0.45	lbs/MMBtu	Acid Rain NO <sub>x</sub> Limit	2160.9	9464.7
VOC (NMOC)	0.06	lb/ton	AP-42 Table 1.1-19	13.53	59.25	0.07	lb/ton	AP-42 Table 1.1-19	13.5	59.2
CO	0.50	lb/ton	AP-42 Table 1.1-3	112.73	493.74	0.50	lb/ton	AP-42 Table 1.1-3	112.7	493.7
HCL	1.2	lb/ton	AP-42 Table 1.1-5	270.54	1,184.97	0.002	lbs/MMBtu	NESHAP Limit <sup>(7)</sup>	9.60	42.1
HF	0.15	lb/ton	AP-42 Table 1.1-5	33.82	148.12	6.00E-05	lbs/MMBtu	NESHAP Limit <sup>(7)</sup>	0.29	1.3
Mercury	16	lbs/Tbtu	AP-42 Table 1.1-17	3,607.20	15,799.54	1.2	lbs/Tbtu	NESHAP Limit <sup>(7)</sup>	5.8E-03	2.5E-02
Benzene	0.0013	lb/ton	AP-42 Table 1.1-14 <sup>(5)</sup>	0.29	1.28	0.0013	lb/ton	AP-42 Table 1.1-14 <sup>(2)</sup>	0.29	1.28
Cyanide	0.0025	lb/ton	AP-42 Table 1.1-14 <sup>(5)</sup>	0.56	2.47	0.0025	lb/ton	AP-42 Table 1.1-14 <sup>(2)</sup>	0.56	2.47
PCDD/ PCDF	1.76E-09	lb/ton	AP-42 Table 1.1-12 <sup>(5)</sup>	4E-07	1.7E-06	1.76E-09	lb/ton	AP-42 Table 1.1-12 <sup>(2)</sup>	4E-07	1.7E-06
Selenium	0.13	lb/ton	Adj for unctr CE 95% <sup>(6)</sup>	29.31	128.37	0.0013	lb/ton	AP-42 Table 1.1-18	2.9E-01	1.3E+00
Cadmium	0.0051	lb/ton	Adj for unctr CE 95% <sup>(6)</sup>	1.15	5.04	0.000051	lb/ton	AP-42 Table 1.1-18	1.1E-02	5.0E-02
Chromium	0.026	lb/ton	Adj for unctr CE 95% <sup>(6)</sup>	5.86	25.67	0.00026	lb/ton	AP-42 Table 1.1-18	5.9E-02	2.6E-01
Manganese	0.049	lb/ton	Adj for unctr CE 95% <sup>(6)</sup>	11.05	48.39	0.00049	lb/ton	AP-42 Table 1.1-18	1.1E-01	4.8E-01
Nickel	0.028	lb/ton	Adj for unctr CE 95% <sup>(6)</sup>	6.31	27.65	0.00028	lb/ton	AP-42 Table 1.1-18	6.3E-02	2.8E-01
Beryllium	0.0021	lb/ton	Adj for unctr CE 95% <sup>(6)</sup>	4.7E-01	2.07	0.000021	lb/ton	AP-42 Table 1.1-18	4.7E-03	2.1E-02
Arsenic	0.041	lb/ton	Adj for unctr CE 95% <sup>(6)</sup>	9.24	40.49	0.00041	lb/ton	AP-42 Table 1.1-18	9.2E-02	4.0E-01
Lead	0.042	lb/ton	Adj for unctr CE 95% <sup>(6)</sup>	9.47	41.47	0.00042	lb/ton	AP-42 Table 1.1-18	9.5E-02	4.1E-01
CO <sub>2</sub>	6040	lb/ton	AP-42 Table 1.1-20	1,361,718.00	5,964,324.84	6040	lb/ton	AP-42 Table 1.1-20	1,361,718	5,964,325
CH <sub>4</sub>	0.04	lb/ton	AP-42 Table 1.1-19	9.02	39.50	0.04	lb/ton	AP-42 Table 1.1-19	9.02	39.50
N <sub>2</sub> O	0.08	lb/ton	AP-42 Table 1.1-19	18.04	79.00	0.08	lb/ton	AP-42 Table 1.1-19	18.04	79.00
				HAPs	17,455.52				HAPs	50.30

**Methodology**

- (1) Maximum Firing Rate (ton/hr) = Heat Input (MMBtu/hr) /Heat Content (Btu/lb) x 1,000,000 x 1 ton/2000 lbs
- (2) Potential Throughput (tons/year) = max firing rate (tons/hr) x 8,760 hrs/yr
- (3) Heat Content, Sulfur Content and Sulfur Content of the Coal provided by Duke Energy
- (4) Emission Factors are from AP-42 Chapter 1.1 (Update 9/98)
- (5) AP-42 Table 1.1-12 and 1.1-14 controlled emissions, no information available on control efficiency.
- (6) AP-42 Table 1.1-18 controlled emissions factors divided by 0.01 to reflect uncontrolled emissions
- (7) Controlled emissions based on NESHAP Subpart UUUUU

**Appendix A: Emission Calculations**  
**326 IAC 6-2-4 (Particulate Emission Limitations for Sources of Indirect Heating)**

**Company Name:** Duke Energy Indiana, LLC - Cayuga Generating Station  
**Source Address:** 3300 N SR 63, Cayuga, Indiana 47928  
**Permit Number:** 165-47094-00001  
**Reviewer:** Christopher Chin

Indirect Heating Units Which Were Existing and in Operation On or Before June 8, 1972						
Facility	Construction Date	Operating Capacity (MMBtu/hr)	Q (MMBtu/hr)	Calculated Pt (lb/MMBtu)	Particulate Limitation, (Pt) (lb/MMBtu)	PM PTE based on AP-42 (lb/MMBtu)
Boiler 1	1967	4,802	9,677	0.234	0.234	0.014
Boiler 2	1968	4,802				
Auxiliary Boiler	1968	73				

**Methodology**

326 IAC 6-2-4 (Particulate Emission Limitations for Sources of Indirect Heating)

$$Pt = \frac{C \times a \times h}{76.5 \times Q^{0.75} \times N^{0.25}}$$

Pounds of particulate matter emitted per million British thermal units (lb/MMBtu).	Pt (units)	Boilers 1 and 2	Aux Boilers
Total source maximum operating capacity rating in MMBtu/hr heat input. The maximum operating capacity rating is defined as the maximum capacity at which the facility is operated or the nameplate capacity, whichever is specified in the facility's permit application, except when some lower capacity is contained in the facility's operation permit; in which case, the capacity specified in the operation permit shall be used.	Q (MMBtu/hr)	9,604	73
Maximum ground level concentration with respect to distance from the point source at the "critical" wind speed for level terrain. This shall equal fifty (50) micrograms per cubic meter for a period not to exceed a sixty (60) minute time period.	C (F/m3)	50	50
Plume rise factor which is used to make allowance for less than theoretical plume rise. The value sixty-seven tenths (0.67) shall be used for Q less than or equal to one thousand (1,000) million British thermal units per hour heat input.	a	0.8	0.8
Number of stacks in fuel burning operation.	N (number of stacks)	2	3
Stack height in feet. If a number of stacks of different heights exist, the average stack height to represent stacks shall be calculated by weighing each stack height with its particulate matter emission rate as follows:	h (average stack height)	500	573.7

**Appendix A: Emissions Calculations**  
**Auxiliary Boiler Emissions**

**Company Name:** Duke Energy Indiana, LLC - Cayuga Generating Station  
**Address City IN Zip:** 3300 N SR 63, Cayuga, Indiana 47928  
**Permit Number:** 165-47094-00001  
**Reviewer:** Christopher Chin

One (1) Auxiliary Boiler, identified as emission unit Aux, with a maximum heat input capacity of 72.76 MMBtu/hr fired with distillate oil and exhausting out one stack identified as stack Aux-1. The Auxiliary boiler was constructed before 1968. [Under NESHAP 40 CFR 63, Subpart

Heat Input Capacity	72.76	MMBtu/hr
Heat Content FO	140000	Btu/gal
Firing Rate	0.52	Kgal/hr
Potential Throughput	4555.2	Kgal/yr
Sulfur Content	0.0147	%
Ash Content		%
IB MACT Limited Use Boiler	10	% Cap Factor
Limited Throughput	455.52	Kgal/yr

Pollutants	Emission Factor		Reference <sup>(4)</sup>	Uncontrolled PTE		Controlled PTE	
	Value	Units		lbs/hr	tons/yr	lbs/hr	tons/yr
SO <sub>2</sub>	2.0874	lbs/Kgal	AP-42 Table 1.3-1	1.09	4.75	1.09	0.48
NO <sub>x</sub>	20	lbs/Kgal	AP-42 Table 1.3-1	10.40	45.55	10.40	4.56
VOC (NMOC)	0.252	lbs/Kgal	AP-42 Table 1.3-3	0.13	0.57	0.13	0.06
CO	5	lbs/Kgal	AP-42 Table 1.3-1	2.60	11.39	2.60	1.14
PM filterable	2	lbs/Kgal	AP-42 Table 1.3-1	1.04	4.56	1.04	0.46
PM condensible	1.3	lbs/Kgal	AP-42 Table 1.3-2	0.68	2.96	0.68	0.30
PM10 filterable	1	lbs/Kgal	AP-42 Table 1.3-6	0.52	2.28	0.52	0.23
PM2.5 filterable	0.25	lbs/Kgal	AP-42 Table 1.3-6	0.13	0.57	0.13	0.06
As	4	lbs/Tbtu	AP-42 Table 1.3-10	2.08E-04	9.11E-04	2.08E-04	9.11E-05
Be	3	lbs/Tbtu	AP-42 Table 1.3-10	1.56E-04	6.83E-04	1.56E-04	6.83E-05
Cd	3	lbs/Tbtu	AP-42 Table 1.3-10	1.56E-04	6.83E-04	1.56E-04	6.83E-05
Cr	3	lbs/Tbtu	AP-42 Table 1.3-10	1.56E-04	6.83E-04	1.56E-04	6.83E-05
Cu	6	lbs/Tbtu	AP-42 Table 1.3-10	3.12E-04	1.37E-03	3.12E-04	1.37E-04
Pb	9	lbs/Tbtu	AP-42 Table 1.3-10	4.68E-04	2.05E-03	4.68E-04	2.05E-04
Hg	3	lbs/Tbtu	AP-42 Table 1.3-10	1.56E-04	6.83E-04	1.56E-04	6.83E-05
Mn	6	lbs/Tbtu	AP-42 Table 1.3-10	3.12E-04	1.37E-03	3.12E-04	1.37E-04
Ni	3	lbs/Tbtu	AP-42 Table 1.3-10	1.56E-04	6.83E-04	1.56E-04	6.83E-05
Se	15	lbs/Tbtu	AP-42 Table 1.3-10	7.80E-04	3.42E-03	7.80E-04	3.42E-04
Zn	4	lbs/Tbtu	AP-42 Table 1.3-10	2.08E-04	9.11E-04	2.08E-04	9.11E-05
CO <sub>2</sub>	22509.20	lbs/Kgal	EPA 40 CFR Part 98	11704.78	51266.95	11704.78	5126.69
N <sub>2</sub> O	0.18	lbs/Kgal	EPA 40 CFR Part 98	0.09	0.40	0.09	0.04
CH <sub>4</sub>	0.90	lbs/Kgal	EPA 40 CFR Part 98	0.47	2.06	0.47	0.21
			Comb HAPs		1.34E-02		1.34E-03
			Individual HAPS (Se)		3.42E-03		3.42E-04

**Methodology**

1 gallon of No. 2 Fuel Oil has a heating value of 140,000 Btu

Potential Throughput (kgals/year) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1kgal per 1000 gallon x 1 gal per 0.140 MM

Emission Factors are from AP 42, Tables 1.3-1, 1.3-2, and 1.3-3 (SCC 1-02-005-01/02/03) Supplement E 9/98

Emission (tons/yr) = Throughput (kgals/ yr) x Emission Factor (lb/kgal)/2,000 lb/ton



**Appendix A: Emissions Calculations  
3A,3B,3C and 3D Emissions**

**Company Name: Duke Energy Indiana, LLC - Cayuga Generating Station  
Address City IN Zip: 3300 N SR 63, Cayuga, Indiana 47928  
Permit Number: 165-47094-00001  
Reviewer: Christopher Chin**

Engine 3A,3B,3C and 3D  
Engine Type CI, nonemergency  
Hp Rating 3600 Hp (each engine)  
Heat Input Capacity 30 MMBtu/hr (each engine)  
Sulfur Content 0.0147 %S  
Control Oxidation Catalyst  
CO, Organic HAPs and HC 70% CE (esitimated)

Pollutant	Emissions Factor	Units	Source	Engine 3A		Engine 3B		Engine 3C		Engine 3D		Uncontrolled PTE Total (4) Engines	
				lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr
PM (filterable)	0.062	lbs/MMBtu	AP-42 Table 3.4-2	1.86	8.15	1.86	8.15	1.86	8.15	1.86	8.15	7.44	32.59
PM10 (total)	0.0573	lbs/MMBtu	AP-42 Table 3.4-2	1.72	7.53	1.72	7.53	1.72	7.53	1.72	7.53	6.88	30.12
PM2.5 (total)	0.0556	lbs/MMBtu	AP-42 Table 3.4-2	1.67	7.31	1.67	7.31	1.67	7.31	1.67	7.31	6.67	29.22
NOx	3.2	lbs/MMBtu	AP-42 Table 3.4-1	96.00	420.48	96.00	420.48	96.00	420.48	96.00	420.48	384.00	1681.92
SO2	0.014847	lbs/MMBtu	AP-42 Table 3.4-1	0.45	1.95	0.45	1.95	0.45	1.95	0.45	1.95	1.78	7.80
CO	8.50E-01	lbs/MMBtu	AP-42 Table 3.4-1	25.50	111.69	25.50	111.69	25.50	111.69	25.50	111.69	102.00	446.76
VOC(a)	9.00E-02	lbs/MMBtu	AP-42 Table 3.4-1	2.70	11.83	2.70	11.83	2.70	11.83	2.70	11.83	10.80	47.30
Benzene	7.76E-04	lbs/MMBtu	AP-42 Table 3.4-3	2.33E-02	1.02E-01	2.33E-02	1.02E-01	2.33E-02	1.02E-01	2.33E-02	1.02E-01	9.31E-02	4.08E-01
Toluene	2.81E-04	lbs/MMBtu	AP-42 Table 3.4-3	8.43E-03	3.69E-02	8.43E-03	3.69E-02	8.43E-03	3.69E-02	8.43E-03	3.69E-02	3.37E-02	1.48E-01
Xylene	1.93E-04	lbs/MMBtu	AP-42 Table 3.4-3	5.79E-03	2.54E-02	5.79E-03	2.54E-02	5.79E-03	2.54E-02	5.79E-03	2.54E-02	2.32E-02	1.01E-01
Formaldehyde	7.79E-05	lbs/MMBtu	AP-42 Table 3.4-3	2.34E-03	1.02E-02	2.34E-03	1.02E-02	2.34E-03	1.02E-02	2.34E-03	1.02E-02	9.35E-03	4.09E-02
Acetaldehyde	2.52E-05	lbs/MMBtu	AP-42 Table 3.4-3	7.56E-04	3.31E-03	7.56E-04	3.31E-03	7.56E-04	3.31E-03	7.56E-04	3.31E-03	3.02E-03	1.32E-02
Acrolein	7.88E-06	lbs/MMBtu	AP-42 Table 3.4-3	2.36E-04	1.04E-03	2.36E-04	1.04E-03	2.36E-04	1.04E-03	2.36E-04	1.04E-03	9.46E-04	4.14E-03
Naphthalene	1.30E-04	lbs/MMBtu	AP-42 Table 3.4-3	3.90E-03	1.71E-02	3.90E-03	1.71E-02	3.90E-03	1.71E-02	3.90E-03	1.71E-02	1.56E-02	6.83E-02
CO2	1.65E+02	lbs/MMBtu	AP-42 Table 3.4-1	4950.00	21681.00	4950.00	21681.00	4950.00	21681.00	4950.00	21681.00	19800.00	86724.00
CH4	6.35E-05	lbs/hp-hr	40 CFR Part 98	2.28E-01	1.00	2.28E-01	1.00	2.28E-01	1.00	2.28E-01	1.00	0.91	4.00
N2O	9.30E-06	lbs/hp-hr	40 CFR Part 98	3.35E-02	0.15	3.35E-02	0.15	3.35E-02	0.15	3.35E-02	0.15	0.13	0.59
				HAPs		0.20		0.20		0.20		0.78	

**Appendix A: Emissions Calculations  
3A,3B,3C and 3D Emissions**

Pollutant	Emissions Factor	Units	Source	Engine 3A		Engine 3B		Engine 3C		Engine 3D		Controlled PTE	
				lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr
PM (filterable)	0.062	lbs/MMBtu	AP-42 Table 3.4-2	1.86	8.15	1.86	8.15	1.86	8.15	1.86	8.15	7.44	32.59
PM10 (total)	0.0573	lbs/MMBtu	AP-42 Table 3.4-2	1.72	7.53	1.72	7.53	1.72	7.53	1.72	7.53	6.88	30.12
PM2.5 (total)	0.0556	lbs/MMBtu	AP-42 Table 3.4-2	1.67	7.31	1.67	7.31	1.67	7.31	1.67	7.31	6.67	29.22
NOx	3.2	lbs/MMBtu	AP-42 Table 3.4-1	96.00	420.48	96.00	420.48	96.00	420.48	96.00	420.48	384.00	1681.92
SO2	0.014847	lbs/MMBtu	AP-42 Table 3.4-1	0.45	1.95	0.45	1.95	0.45	1.95	0.45	1.95	1.78	7.80
CO	8.50E-01	lbs/MMBtu	AP-42 Table 3.4-1	7.65	33.51	7.65	33.51	7.65	33.51	7.65	33.51	30.60	134.03
VOC(a)	9.00E-02	lbs/MMBtu	AP-42 Table 3.4-1	0.81	3.55	0.81	3.55	0.81	3.55	0.81	3.55	3.24	14.19
Benzene	7.76E-04	lbs/MMBtu	AP-42 Table 3.4-3	0.0070	3.06E-02	0.0070	3.06E-02	0.0070	3.06E-02	0.0070	3.06E-02	2.79E-02	1.22E-01
Toluene	2.81E-04	lbs/MMBtu	AP-42 Table 3.4-3	0.0025	1.11E-02	0.0025	1.11E-02	0.0025	1.11E-02	0.0025	1.11E-02	1.01E-02	4.43E-02
Xylene	1.93E-04	lbs/MMBtu	AP-42 Table 3.4-3	0.0017	7.61E-03	0.0017	7.61E-03	0.0017	7.61E-03	0.0017	7.61E-03	6.95E-03	3.04E-02
Formaldehyde	7.79E-05	lbs/MMBtu	AP-42 Table 3.4-3	0.0007	3.07E-03	0.0007	3.07E-03	0.0007	3.07E-03	0.0007	3.07E-03	2.80E-03	1.23E-02
Acetaldehyde	2.52E-05	lbs/MMBtu	AP-42 Table 3.4-3	0.0002	9.93E-04	0.0002	9.93E-04	0.0002	9.93E-04	0.0002	9.93E-04	9.07E-04	3.97E-03
Acrolein	7.88E-06	lbs/MMBtu	AP-42 Table 3.4-3	0.0001	3.11E-04	0.0001	3.11E-04	0.0001	3.11E-04	0.0001	3.11E-04	2.84E-04	1.24E-03
Naphthalene	1.30E-04	lbs/MMBtu	AP-42 Table 3.4-3	0.0012	5.12E-03	0.0012	5.12E-03	0.0012	5.12E-03	0.0012	5.12E-03	4.68E-03	2.05E-02
CO2	1.65E+02	lbs/MMBtu	AP-42 Table 3.4-1	4950.00	21681.00	4950.00	21681.00	4950.00	21681.00	4950.00	21681.00	19800.00	86724.00
CH4	6.35E-05	lbs/hp-hr	40 CFR Part 98	2.28E-01	1.00	2.28E-01	1.00	2.28E-01	1.00	2.28E-01	1.00	0.91	4.00
N2O	9.30E-06	lbs/hp-hr	40 CFR Part 98	3.35E-02	0.15	3.35E-02	0.15	3.35E-02	0.15	3.35E-02	0.15	0.13	0.59
				HAPs	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.24	

AP-42 Section 3.4, Large Stationary Diesel and All Stationary Dual Fired Engines, Table 3.4.1 and Table 3.4-2  
Assumes 91% nonmethane and 9% methane (non volatile organic compound).

**Appendix A: Emissions Calculations  
Coal Handling**

**Company Name: Duke Energy Indiana, LLC - Cayuga Generating Station**  
**Address City IN Zip: 3300 N SR 63, Cayuga, Indiana 47928**  
**Permit Number: 165-47094-00001**  
**Reviewer: Christopher Chin**

Emission Unit : Dual conveyor coal processing system  
 Potential Coal Throughput 3,949,884.00 tons/yr, based on maximum firing rate, and continuous hours of operation.

Transfer Point	Description	Control Description	Control Efficiency	Uncontrolled (tons/yr)			Controlled (tons/yr)		
				PM	PM10	PM2.5	PM	PM10	PM2.5
DP-1	Rail Car to Hopper	Enclosure	50%	0.9794	0.4632	0.0701	0.4897	0.2316	0.0351
DP-2	Hopper to Conveyor A	Enclosure	50%	0.9794	0.4632	0.0701	0.4897	0.2316	0.0351
DP-3	Conveyor A to Conveyor B	Enclosure	50%	0.9794	0.4632	0.0701	0.4897	0.2316	0.0351
DP-4	Conveyor B to Conveyor C	Enclosure	50%	0.9794	0.4632	0.0701	0.4897	0.2316	0.0351
DP-5	Conveyor C to Conveyor D	Enclosure	50%	0.9794	0.4632	0.0701	0.4897	0.2316	0.0351
DP-6	Conveyor D to Tripper	Enclosure	50%	0.9794	0.4632	0.0701	0.4897	0.2316	0.0351
DP-7	Tripper to Bunker	Enclosure with Rotoclone	99.9%	0.9794	0.4632	0.0701	0.0010	0.0005	0.0001
DP-8	Conveyor B to Conveyor E	Enclosure	50%	0.9794	0.4632	0.0701	0.4897	0.2316	0.0351
DP-9	Conveyor E to Coal Pile	Telescopic Chute	90%	0.9794	0.4632	0.0701	0.0979	0.0463	0.0070
DP-10	Pile to Reclaim Hopper	Enclosure	50%	0.9794	0.4632	0.0701	0.4897	0.2316	0.0351
DP-11	Reclaim to Feeder	Enclosure	50%	0.9794	0.4632	0.0701	0.4897	0.2316	0.0351
DP-12	Feeder to Conveyor F	Enclosure	50%	0.9794	0.4632	0.0701	0.4897	0.2316	0.0351
DP-13	Conveyor F to Conveyor A	Enclosure	50%	0.9794	0.4632	0.0701	0.4897	0.2316	0.0351
DP-14	Truck unloading to Pile			0.9794	0.4632	0.0701	0.9794	0.4632	0.0701
Unloading Truck to Pile then to Bunker				9.7941	4.6324	0.7015	4.8980	2.3166	0.3508
Unload Train to Bunker				6.8559	3.2426	0.4910	2.9392	1.3902	0.2105
Unload Train to Pile then to Bunker (Worst case operating senario).				<b>12.7324</b>	<b>6.0221</b>	<b>0.9119</b>	<b>5.4857</b>	<b>2.5946</b>	<b>0.3929</b>

AP-42 equation for particulate emissions associated with aggregate drop operations:

$$k (0.0032) (U/5)^{1.3} / [(M/2)^{1.4}]$$

where:

k =	0.053	[particles < 2.5um]
k =	0.35	[particles < 10um]
k =	0.74	[particles < 30um]
U =	5.7	[mph, max. speed of enclosed conveyors approx. 500 fpm]
M =	Material moisture content, see Table 13.2.4-1	
M =	6.9	percent, see, AP-42 Table 13.2.4-1
E (lb PM per ton material handled) =	0.000496	
E (lb PM <sub>10</sub> per ton material handled) =	0.000235	
E (lb PM <sub>2.5</sub> per ton material handled) =	0.000036	

**Appendix A: Emissions Calculations**  
**Emissions from Limestone Handling Operation**

**Company Name: Duke Energy Indiana, LLC - Cayuga Generating Station**  
**Address City IN Zip: 3300 N SR 63, Cayuga, Indiana 47928**  
**Permit Number: 165-47094-00001**  
**Reviewer: Christopher Chin**

**Uncontrolled PM/PM10 emissions:**

Emission Point	Unit Description	Number of Units	Max. Capacity (tons/hr)	PM Emission Factor* (lbs/ton)	Uncontrolled PM Emissions (lbs/hr/unit)	Uncontrolled PM Emissions (tons/yr)	PM10 Emission Factor* (lbs/ton)	Uncontrolled PM10 Emissions (lbs/hr/unit)	Uncontrolled PM10 Emissions (tons/yr)
EP-L1	Railcar/Truck Unloading	1	1,000	0.0001	0.10	0.44	0.0001	0.10	0.44
EP-L2	Hoppers	2	500	0.0030	1.50	13.1	0.0011	0.55	4.82
EP-L2	Belt Feeders	2	500	0.0030	1.50	13.1	0.0011	0.55	4.82
EP-L3	Conveyor LH-1	1	1,000	0.0030	3.00	13.1	0.0011	1.10	4.82
EP-L4	Reclaim Hoppers	2	200	0.0030	0.60	5.26	0.0011	0.22	1.93
EP-L4	Belt Feeders	2	200	0.0030	0.60	5.26	0.0011	0.22	1.93
EP-L18b	Conveyor LH-2	1	400	0.0030	1.20	5.26	0.0011	0.44	1.93
EP-L18a & c	Conveyor LH-3	1	400	0.0030	1.20	5.26	0.0011	0.44	1.93
EP-L16	Day Bin Unit 1	1	400	0.0030	1.20	5.26	0.0011	0.44	1.93
EP-L17	Day Bin Unit 2	1	400	0.0030	1.20	5.26	0.0011	0.44	1.93
<b>Total</b>						<b>71.4</b>			<b>26.5</b>

\* These emission factors are from AP-42, Table 11.19.2-2 (08/04).

**Methodology**

Uncontrolled PTE (lbs/hr/unit) = Max. Capacity (tons/hr) x Emission Factor (lbs/ton)

Uncontrolled PTE (tons/yr) = Number of Units x Max. Capacity (tons/hr) x Emission Factor (lbs/ton) x 8760 hrs/yr x 1 ton/2000 lbs

**Controlled PM/PM10 emissions:**

**Throughput Limit: 509,000 tons/yr**

Emission Point	Unit	Number of Units	PM Emission Factor* (lb/ton)	PM10 Emission Factor* (lb/ton)	Control Method	Control Efficiency** (%)	Controlled PM Emissions (lbs/ton)	Controlled PM10 Emissions (lbs/ton)	Controlled PM Emissions (tons/yr)	Controlled PM10 Emissions (tons/yr)
EP-L1	Railcar/Truck Unloading	1	0.00010	0.00010	Fogging or wet suppress	75.0%	2.50E-05	2.50E-05	6.36E-03	6.36E-03
EP-L2	2 Hoppers	2	0.00300	0.00110	Fogging or wet suppress	75.0%	7.50E-04	2.75E-04	0.38	0.14
EP-L2	2 Belt Feeders	2	0.00300	0.00110	Fogging or wet suppress	75.0%	7.50E-04	2.75E-04	0.38	0.14
EP-L3	1 Conveyor LH-1	1	0.00300	0.00110	Telescoping Chute	50.0%	1.50E-03	5.50E-04	0.38	0.14
EP-L4	2 Reclaim Hoppers	2	0.00300	0.00110	Fogging or wet suppress	75.0%	7.50E-04	2.75E-04	0.38	0.14
EP-L4	2 Belt Feeders	2	0.00300	0.00110	Fogging or wet suppress	75.0%	7.50E-04	2.75E-04	0.38	0.14
EP-L18abc	1 Conveyor LH-2	1	0.00300	0.00110	Fogging or wet suppress	75.0%	7.50E-04	2.75E-04	0.19	0.07
EP-L18abc	1 Conveyor LH-3	1	0.00300	0.00110	Fogging or wet suppress	75.0%	7.50E-04	2.75E-04	0.19	0.07
EP-L16 and 17	Day Bin Unit 1	1	0.00300	0.00110		0.0%	3.00E-03	1.10E-03	0.76	0.28
EP-L17	Day Bin Unit 2	1	0.00300	0.00110		0.0%	3.00E-03	1.10E-03	0.76	0.28
<b>Total</b>									<b>3.82</b>	<b>1.41</b>

\* These emission factors are from AP-42, Table 11.19.2-2 (08/04).

\*\* Control efficiencies were provided by the equipment vendor and were based on engineering judgment.

**Methodology**

Controlled PM/PM10 Emissions (lbs/ton) = Emission Factor (lbs/ton) x (1-Control Efficiency)

Controlled PM/PM10 Emissions (tons/yr) = Throughput Limit (tons/yr) x Emission Factor (lbs/ton) x (1-Control Efficiency) x 1 ton/2000 lbs x Number of Units

**Appendix A: Emissions Calculations  
Emissions from Gypsum Handling System**

**Company Name: Duke Energy Indiana, LLC - Cayuga Generating Station**  
**Address City IN Zip: 3300 N SR 63, Cayuga, Indiana 47928**  
**Permit Number: 165-47094-00001**  
**Reviewer: Christopher Chin**

Gypsum Throughput 900528.00 tons/yr

ID	Transfer Points	Emission Controls	Number of Transfer Points	Emissions Factors (lbs/ton)			Control Description	Ctrl Eff	Uncontrolled PTE (tons/yr)			Controlled PTE (tons/yr)		
				PM	PM10	PM2.5			PM	PM10	PM2.5	PM	PM10	PM2.5
EP-G1	Emissions from Gypsum Dewatering Building - Six Transfer Points, gypsum from vacuum belt feeder A, B and C to Conveyor GH-1A and GH-1B .	Enclosed transfer point.	6	0.003219	0.001523	0.000231	No additional Control	0%	1.45	0.69	0.10	1.450	0.686	0.104
EP-G2	Transfer of gypsum from Conveyor GH-1B to Radial Stacker Conveyor GH-2B within Transfer Tower 1B.	Enclosed transfer point.	1	0.003219	0.001523	0.000231	No additional Control	0%	1.45	0.69	0.10	1.450	0.686	0.104
EP-G3	Transfer of gypsum from Conveyor GH-1A to Radial Stacker Conveyor GH-2A within Transfer Tower 1A.	Enclosed transfer point.	1	0.003219	0.001523	0.000231	No additional Control	0%	1.45	0.69	0.10	1.450	0.686	0.104
EP-G4	Transfer of gypsum from Radial Stacker Conveyor GH-2A to Gypsum Stockout Pile.	Exposed transfer point.	1	0.000597	0.000282	0.000043	No additional Control	0%	0.27	0.13	0.02	0.269	0.127	0.019
EP-G5	Emissions from gypsum handling at Transfer House 2, Emissions from gypsum handling at Transfer House 2	Exposed transfer point.	1	0.000597	0.000282	0.000043	telescoping chute	50%	0.27	0.13	0.02	0.134	0.064	0.010
<b>Total</b>									<b>4.89</b>	<b>2.31</b>	<b>0.35</b>	<b>4.75</b>	<b>2.25</b>	<b>0.34</b>

$E = k (0.0032) (U/5)^{1.3} / [(M/2)^{1.4}]$  (AP42 Section 13.2.4, Eqn 1)

where:

- k = 0.74 [particles < 30um]
- k = 0.35 [particles < 10um]
- k = 0.053 [particles < 2.5um]
- U<sub>exposed</sub> = 9.8 [mph, mean wind speed, Indianapolis International Airport, 2005]
- U<sub>enclosed</sub> = 3.0 [mph, mean wind speed for enclosed transfer points]
- M<sub>Cond.Gypsum</sub> = 10.00 Moisture content of gypsum product after dewatering.

**Conditioned As Unconditioned**

	Exposed Transfer Points	Enclosed Transfer Points	
E (PM) =	0.00060	0.00322	lb / ton material transferred
E (PM10) =	0.00028	0.00152	lb / ton material transferred
E (PM2.5) =	0.00004	0.00023	lb / ton material transferred

**Appendix A: Emissions Calculations  
Emissions from Dry Sorbent Injection System**

<b>Company Name:</b> Duke Energy Indiana, LLC - Cayuga Generating Station	2365.5 1272.83
<b>Address City IN Zip:</b> 3300 N SR 63, Cayuga, Indiana 47928	118.275 63.6415
<b>Permit Number:</b> 165-47094-00001	177.413 95.4623
<b>Reviewer:</b> Christopher Chin	14.7844 7.95519

**SORBENT REQUIREMENT**

Maximum Hourly Sorbent Consumption:	8,000 lb lime/hr (both units) (S&L "FGD-Byproduct Fixation Design Basis," Draft, 4/24/13)
Maximum Annual Sorbent Consumption:	35,040 tons/year (based on 100% capacity factor, both units)
Sorbent Loading Hours:	2,628 hr/yr (based on 20 ton trucks, assumes 1.5 hour to load truck)

Emission Point:	Description	Emission Controls	Emission Factors				Uncontrolled PTE			Controlled PTE		
			PM Control at Emission Point	Em Rate (g/dscf)	ACFM	Oper Hours	PM	PM10	PM2.5	PM	PM10	PM2.5
EP-01 (DSI)	Emissions from Unit 1 DSI Sorbent Storage Silo when actively loading	The DSI Sorbent Storage Silo for Unit 1 includes one bin vent filter. Annual emissions assume that EP-01 will operate for 1,314 hr/yr @ 1,000 cfm when actively filling the storage silo, and 7,446 hrs/yr @ 50 cfm with recycling air.	Bin Vent Filter	0.005	1000	1314	3.614	3.614	3.614	0.036	0.036	0.036
	50				7446							
EP-03 (DSI)	Emissions from Unit 2 DSI Sorbent Storage Silo when actively loading	The DSI Sorbent Storage Silo for Unit 2 includes one bin vent filter. Annual emissions assume that EP-01 will operate for 1,314 hr/yr @ 1,000 cfm when actively filling the storage silo, and 7,446 hrs/yr @ 50 cfm with recycling air.	Bin Vent Filter	0.005	1000	1314	3.614	3.614	3.614	0.036	0.036	0.036
	50				7446							
EP-05A, EP-05B, EP-05C (spare)	Emissions from Unit 1 DSI Sorbent Storage Silo Weight Feeders	Unit 1 DSI Sorbent Storage Silo Weight Feeder exhaust points include dust filters. Emission calculations conservatively assume that TP-04 and TP-05 will operate for 24 hrs/day @ 100 cfm each.	Filter	0.005	100	8760	3.754	3.754	3.754	0.038	0.038	0.038
	100				8760							
EP-06A, EP-06B, EP-06C (Spare)	Emissions from Unit 2 DSI Sorbent Storage Silo Weight Feeders	Unit 2 DSI Sorbent Storage Silo Weight Feeder exhaust points include dust filters. Emission calculations conservatively assume that TP-06 and TP-07 will operate for 24 hrs/day @ 100 cfm each.	Filter	0.005	100	8760	3.754	3.754	3.754	0.038	0.038	0.038
	100				8760							
<b>Total</b>							<b>14.736</b>	<b>14.736</b>	<b>14.736</b>	<b>0.147</b>	<b>0.147</b>	<b>0.147</b>

**Appendix A: Emissions Calculations**  
**Emissions from Limestone Handling associated with Arsenic Mitigations System**

**Company Name:** Duke Energy Indiana, LLC - Cayuga Generating Station  
**Address City IN Zip:** 3300 N SR 63, Cayuga, Indiana 47928  
**Permit Number:** 165-47094-00001  
**Reviewer:** Christopher Chin

Limestone Throughput 35,916 tons/yr

Silo Baghouse													
ID	Description	Emission Controls	Emissions Exhausted at Emission Point:	Emission Factors			Hour of Oper	Uncontrolled PTE			Controlled PTE		
				PM Control at Emission Point	Controlled Emission Rate	ACFM		PM tons/yr	PM10 tons/yr	PM2.5 tons/yr	PM tons/yr	PM10 tons/yr	PM2.5 tons/yr
TP-01, TP-02	Emissions from Limestone Storage Silo when actively loading.	Annual emissions assume that EP-01 will operate for 2,694 hr/yr @ 1,200 cfm when actively filling the storage silo, and 6,066 hrs/yr @ 200 cfm.	EP-01	Bin Vent Filter	0.005	1200	2694	9.5	9.5	9.5	0.095	0.095	0.095
	EP-01		Bin Vent Filter	200		6066							
EP-02	Bin vent at top of surge bin	Emissions associated with TP-03	EP-02	Bin Vent Filter	0.005	2,262	8760	42	42	42	0.42	0.420	0.42

Transfer Points										
ID	Description	Emission Controls	PM Control at Emission Point	CE	Uncontrolled PTE			Controlled PTE		
					PM tons/yr	PM10 tons/yr	PM2.5 tons/yr	PM tons/yr	PM10 tons/yr	PM2.5 tons/yr
F-01	Transfer of limestone surge bin to coal reclaim conveyor C-1	Emissions associated with TP-04	Enclosed Transfer	90	0.0539	0.0198	0.0198	0.0054	0.0020	0.0020
F-02	Transfer of limestone surge bin to coal reclaim conveyor C-2	Emissions associated with TP-05	Enclosed Transfer	90	0.0539	0.0198	0.0198	0.0054	0.0020	0.0020

**Emission Factor Calculation -- Limestone Transfer Points**

**Uncontrolled Emission Factor**

E (PM) = 0.0030 lb PM/ton (AP-42 Table 11.19.2-2)  
 E (PM10) = 0.0011 lb PM10/ton (AP-42 Table 11.19.2-2)  
 E (PM2.5) = 0.0011 lb PM2.5/ton (AP-42 Table 11.19.2-2)  
 Control Efficiency 90% Assumed for enclosed limestone transfer point:

**Controlled Emission Factor**

E (PM) = 0.00030 lb PM/ton  
 E (PM10) = 0.00011 lb PM10/ton  
 E (PM2.5) = 0.00011 lb PM2.5/ton

Total	Uncontrolled PTE			Controlled PTE		
	tons/yr	tons/yr	tons/yr	tons/yr	tons/yr	tons/yr
	<b>51.61</b>	<b>51.54</b>	<b>51.54</b>	<b>0.53</b>	<b>0.52</b>	<b>0.52</b>

**Appendix A: Emissions Calculations  
Emissions from Dry Fly Ash Handling**

**Company Name: Duke Energy Indiana, LLC - Cayuga Generating Station  
Address City IN Zip: 3300 N SR 63, Cayuga, Indiana 47928  
Permit Number: 165-47094-00001  
Reviewer: Christopher Chin**

Maximum Hourly Ash Loadout Rate (from pug) 135 ton/hr (theoretical truck loadout rate based on 33 tons discharge in 15 minutes)  
Maximum Ash Collection Rate: 99,755 lb ash (dry)/hr (both units) (S&L "FGD-Byproduct Fixation Design Basis," Draft, 4/24/13)  
Maximum Annual Ash Removed From Site: 514,031 tons/year (based on 100% capacity factor for both units, 15% moisture content)

ID	Description	Emission Point:	Emission Factors			Uncontrolled PTE			Controlled PTE		
			PM Control at Emission Point	Emission Rate	ACFM	PM	PM10	PM2.5	PM	PM10	PM2.5
EP-01	Unit 1 Vacuum exhauster	EP-01	Filter Separator	0.005	5,000	93.86	93.86	93.86	0.94	0.94	0.94
EP-02	Unit 1 Vacuum exhauster	EP-02	Filter Separator	0.005	5,000	93.86	93.86	93.86	0.94	0.94	0.94
EP-03	Unit 2 Vacuum exhauster	EP-03	Filter Separator	0.005	5,000	93.86	93.86	93.86	0.94	0.94	0.94
EP-04	Unit 2 Vacuum exhauster	EP-04	Filter Separator	0.005	5,000	93.86	93.86	93.86	0.94	0.94	0.94
EP-05	Vacuum exhauster (Spare)	EP-05	Filter Separator	0.005	5,000	---	---	---	---	---	---
EP-06	Fly ash silo #1 bin vent filter	EP-06	Bin Vent Filter	0.005	5,000	93.86	93.86	93.86	0.94	0.94	0.94
						<b>469.29</b>	<b>469.29</b>	<b>469.29</b>	<b>4.69</b>	<b>4.69</b>	<b>4.69</b>

ID	Description	Emission Point:	Control	Uncontrolled PTE			Controlled PTE		
				PM	PM10	PM2.5	PM	PM10	PM2.5
F-01	Transfer of conditioned fly ash from pin mixer to haul truck	F-01	15% Moisture Content	3.852	1.822	0.2759	0.087	0.041	0.006
F-04	Fly ash unloaded from trucks	F-04	15% Moisture Content	3.852	1.822	0.2759	0.087	0.041	0.006
				<b>7.70</b>	<b>3.64</b>	<b>0.55</b>	<b>0.17</b>	<b>0.08</b>	<b>0.01</b>

**Conditioned Fly Ash Transfer**

$E = k (0.0032) (U/5)^{1.3} / [(M/2)^{1.4}]$  (AP42 Section 13.2.4, Eqn 1)

where:

- k = 0.74 [particles < 30um]
- k = 0.35 [particles < 10um]
- k = 0.053 [particles < 2.5um]

U<sub>exposed</sub> = 9.8 [mph, mean wind speed, Indianapolis International Airport, 2005]

M<sub>Cond.Ash</sub> = 15.00 Assumed moisture content of Conditioned Ash

Conditioned Ash                      Unconditioned

- E (PM) = 0.00034                      0.01499      lb / ton material transferred
- E (PM10) = 0.00016                      0.00709      lb / ton material transferred
- E (PM2.5) = 0.00002                      0.00107      lb / ton material transferred

Uncontrolled PTE			Controlled PTE		
PM	PM10	PM2.5	PM	PM10	PM2.5
<b>476.99</b>	<b>472.93</b>	<b>469.84</b>	<b>4.87</b>	<b>4.78</b>	<b>4.71</b>



**Appendix A: Emissions Calculations**  
**Emissions from Fixation Process**

**Company Name:** Duke Energy Indiana, LLC - Cayuga Generating Station  
**Address City IN Zip:** 3300 N SR 63, Cayuga, Indiana 47928  
**Permit Number:** 165-47094-00001  
**Reviewer:** Christopher Chin

Design Annual Gypsum Requirement: 613,230 ton gypsum (wet)/yr (assume 100% capacity factor, 5% moisture content)  
 Maximum Annual Fixated Material Throughput: 1,500,114 tons/year (based on 100% capacity factor for both units, 30% moisture content)

**Lime Silo**

ID	Description	Emission Controls	Emission Point:	Emission Factors			Operating Hours	Uncntrl PTE (tons/yr)			Cntrl PTE (tons/yr)		
				Control	Em Rate (g/dscf)	Flow (ACFM)		PM	PM10	PM2.5	PM	PM10	PM2.5
TP-01, TP-02	Emissions from Lime Bin when loading	Annual emissions assume 2,190 hr/yr @ 1,200 cfm when filling the storage silo, and 6,570 hrs/yr @ 200 cfm with recycling air.	EP-02	Bin Vent Filter	0.005	1200	1,290	6.133	6.133	6.133	0.061	0.061	0.061
	EP-02		Bin Vent Filter	0.005	200	6,570							

**Fixation Transfer Points**

ID	Description	Emission Controls	Control Efficiency	Em Factors (lbs/ton)			Throughput	Uncntrl PTE (tons/yr)			Cntrl PTE (tons/yr)		
				PM	PM10	Pm2.5		PM	PM10	PM2.5	PM	PM10	PM2.5
F-02	Transfer of gypsum to new belt feeder	Building Enclosure	0.9	0.00157	0.00074	0.00011	613,229.85	0.483	0.228	0.035	0.048	0.023	0.003
F-03	Pin mixer discharge to conveyor	Building Enclosure	0.9	0.00157	0.00074	0.00011	613,229.852	0.483	0.228	0.035	0.048	0.023	0.003
F-04	Transfer of fixated material to radial stacker	Cntrl 30% Moisture Uncntrl 5% Moisture	0.92	0.00013	0.00006	0.00001	1,500,114	14.511	0.559	0.085	0.096	0.045	0.007
F-05	Transfer of fixated material to waste pile	Cntrl 30% Moisture Uncntrl 5% Moisture	0.92	0.00013	0.00006	0.00001	1,500,114	1.181	0.559	0.085	0.096	0.045	0.007
F-10	Unload fixated material from trucks at LF site	Cntrl 30% Moisture Uncntrl 5% Moisture	0.92	0.00013	0.00006	0.00001	1,500,114	1.181	0.559	0.085	0.096	0.045	0.007
<b>Fixation Total</b>								<b>23.972</b>	<b>8.265</b>	<b>6.456</b>	<b>0.446</b>	<b>0.243</b>	<b>0.089</b>

**Transfer Points**

$E \text{ (lb/ton)} = k (0.0032) (U/5)^{1.3} / (M/2)^{1.4}$  (AP42 Section 13.2.4, Eqn 1)

	Gypsum Transfer Point	Fixated Material Transfer Point (30% Moisture)	Fixated Material Transfer Point (5% Moisture)	Unit	Source
where:	Point	Point	Point		
k (PM) =	0.74	0.74	0.74		AP42 Section 13.2.4, page 4
k (PM10) =	0.35	0.35	0.35		AP42 Section 13.2.4, page 5
k (PM2.5) =	0.053	0.053	0.053		AP42 Section 13.2.4, page 6
Uexposed =	9.8	9.8	9.8	mph	mean wind speed, Indianapolis International Airport, 2005]
Mfix Matl =	5.00	30.00	5.00	%	Assumed moisture content of fixated material
E (PM) =	0.00157	0.00013	0.00157	lb/ton	
E (PM10) =	0.00074	0.00006	0.00074	lb/ton	
E (PM2.5) =	0.00011	0.00001	0.00011	lb/ton	

**Appendix A: Emissions Calculations**  
**Emergency Diesel Engine ENG-1 Emissions**

**Company Name: Duke Energy Indiana, LLC - Cayuga Generating Station**  
**Address City IN Zip: 3300 N SR 63, Cayuga, Indiana 47928**  
**Permit Number: 165-47094-00001**  
**Reviewer: Christopher Chin**

Emissions Unit	Emergency	ENG-1
Output Horsepower Rating (hp)		156.9
Maximum Hours Operated per Year		500
Potential Throughput (hp-hr/yr)		78,450

Pollutant	Emissions Factor	Source	Unit	Controlled PTE		Uncontrolled PTE	
				lbs/hr	tons/yr	lbs/hr	tons/yr
PM <sup>(1)</sup>	2.20E-03	Same as PM10	lbs/Hp-hr	0.35	0.09	0.35	0.09
PM10	2.20E-03	AP42 Table 3.3-1	lbs/Hp-hr	0.35	0.09	0.35	0.09
PM2.5 <sup>(1)</sup>	2.20E-03	Same as PM10	lbs/Hp-hr	0.35	0.09	0.35	0.09
SO2	2.05E-03	AP42 Table 3.3-1	lbs/Hp-hr	0.32	0.08	0.32	0.08
NOx	3.10E-02	AP42 Table 3.3-1	lbs/Hp-hr	4.86	1.22	4.86	1.22
VOC	2.51E-03	AP42 Table 3.3-1	lbs/Hp-hr	0.39	0.10	0.39	0.10
CO	6.68E-03	AP42 Table 3.3-1	lbs/Hp-hr	1.05	0.26	1.05	0.26
Benzene <sup>(3)</sup>	6.53E-06	AP42 Table 3.3-2	lbs/Hp-hr	1.02E-03	2.56E-04	1.02E-03	2.56E-04
Toluene <sup>(3)</sup>	2.86E-06	AP42 Table 3.3-2	lbs/Hp-hr	4.49E-04	1.12E-04	4.49E-04	1.12E-04
Xylene <sup>(3)</sup>	1.96E-05	AP42 Table 3.3-2	lbs/Hp-hr	3.08E-03	7.69E-04	3.08E-03	7.69E-04
1,3-Butadiene <sup>(3)</sup>	2.74E-07	AP42 Table 3.3-2	lbs/Hp-hr	4.29E-05	1.07E-05	4.29E-05	1.07E-05
Formaldehyde <sup>(3)</sup>	8.26E-06	AP42 Table 3.3-2	lbs/Hp-hr	1.30E-03	3.24E-04	1.30E-03	3.24E-04
Acetaldehyde <sup>(3)</sup>	5.37E-06	AP42 Table 3.3-2	lbs/Hp-hr	8.42E-04	2.11E-04	8.42E-04	2.11E-04
Acrolein <sup>(3)</sup>	6.48E-07	AP42 Table 3.3-2	lbs/Hp-hr	1.02E-04	2.54E-05	1.02E-04	2.54E-05
Total PAH <sup>(2)(3)</sup>	1.18E-06	AP42 Table 3.3-2	lbs/Hp-hr	1.85E-04	4.61286E-05	1.85E-04	4.613E-05
			HAPs		1.75E-03		1.75E-03

<sup>(1)</sup> PM and PM2.5 emission factors are assumed to be equivalent to PM10 emission factors.

<sup>(2)</sup> PAH = Polyaromatic Hydrocarbon (PAHs are considered HAPs, since they are considered Polycyclic Organic Matter)

<sup>(3)</sup> Emission factors in lb/hp-hr were calculated using emission factors in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu/ hp-hr (AP-42 Table 3.3-1).

<sup>(5)</sup> Controlled and uncontrolled PTE are the same.

**Appendix A: Emissions Calculations  
Emergency Diesel Engine ENG-2 Emissions**

**Company Name: Duke Energy Indiana, LLC - Cayuga Generating Station  
Address City IN Zip: 3300 N SR 63, Cayuga, Indiana 47928  
Permit Number: 165-47094-00001  
Reviewer: Christopher Chin**

Emissions Unit	Emergency	ENG-2
Output Horsepower Rating (hp)		713.0
Maximum Hours Operated per Year		500
Potential Throughput (hp-hr/yr)		356,500
Sulfur Content (S) of Fuel (% by weight)		0.500

Pollutant	Emissions Factor	Source	Unit	Uncontrolled PTE		Controlled PTE	
				lbs/hr	tons/yr	lbs/hr	tons/yr
PM	0.0007	AP-42 Table 3.4-1	lbs/Hp-hr	0.50	0.12	0.50	0.12
PM10 (3)	0.0004011	AP-42 Table 3.4-2	lbs/Hp-hr	0.29	0.07	0.29	0.07
PM2.5 (3)	0.0003892	AP-42 Table 3.4-2	lbs/Hp-hr	0.28	0.07	0.28	0.07
SO2	0.004045	AP-42 Table 3.4-1	lbs/Hp-hr	2.88	0.72	2.88	0.72
NO <sub>x</sub> (1)	0.024	AP-42 Table 3.4-1	lbs/Hp-hr	17.11	4.28	9.27	2.32
VOC	0.000705	AP-42 Table 3.4-1	lbs/Hp-hr	0.50	0.13	0.50	0.13
CO	0.0055	AP-42 Table 3.4-1	lbs/Hp-hr	3.92	0.98	3.92	0.98
Benzene (3)	5.43E-06	AP-42 Table 3.4-3	lbs/Hp-hr	3.87E-03	9.68E-04	0.00	9.68E-04
Toluene (3)	1.97E-06	AP-42 Table 3.4-3	lbs/Hp-hr	1.40E-03	3.51E-04	0.00	3.51E-04
Xylene (3)	1.35E-06	AP-42 Table 3.4-3	lbs/Hp-hr	9.63E-04	2.41E-04	0.00	2.41E-04
Formaldehyde (3)	5.52E-07	AP-42 Table 3.4-3	lbs/Hp-hr	3.94E-04	9.84E-05	0.00	9.84E-05
Acetaldehyde (3)	1.76E-07	AP-42 Table 3.4-3	lbs/Hp-hr	1.26E-04	3.14E-05	0.00	3.14E-05
Acrolein (3)	5.52E-08	AP-42 Table 3.4-3	lbs/Hp-hr	3.93E-05	9.83E-06	0.00	9.83E-06
Total PAH (3)	1.48E-06	AP-42 Table 3.4-4	lbs/Hp-hr	1.06E-03	2.65E-04	0.00	2.65E-04
CO2	1.16E+00	AP-42 Table 3.4-1	lbs/Hp-hr	827.08	206.77	827.08	206.77
CH4 (4)	6.35E-05	40 CFR Part 98	lbs/Hp-hr	4.52E-02	1.13E-02	0.05	1.13E-02
N2O (4)	9.30E-06	40 CFR Part 98	lbs/Hp-hr	6.63E-03	1.66E-03	0.01	1.66E-03
				HAPs	9.82E-01	9.82E-01	

(1) NO<sub>x</sub> emission factor: uncontrolled = 0.024 lb/hp-hr, controlled by ignition timing retard = 0.013 lb/hp-hr

(2) PAH = Polyaromatic Hydrocarbon (PAHs are considered HAPs, since they are considered Polycyclic Organic Matter)

(3) Emission factors in lb/hp-hr were calculated using emission factors in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu/ hp-hr .

**Appendix A: Emissions Calculations  
Emergency Diesel Engine ENG-3 Emissions**

**Company Name: Duke Energy Indiana, LLC - Cayuga Generating Station  
Address City IN Zip: 3300 N SR 63, Cayuga, Indiana 47928  
Permit Number: 165-47094-00001  
Reviewer: Christopher Chin**

Emissions Unit	Emergency	ENG-3
Output Horsepower Rating (hp)		430.0
Maximum Hours Operated per Year		500
Potential Throughput (hp-hr/yr)		215,000
Sulfur Content (S) of Fuel (% by weight)		0.500

Pollutant	Emissions Factor	Source	Unit	Uncontrolled PTE		Controlled PTE	
				lbs/hr	tons/yr	lbs/hr	tons/yr
PM	0.0007	AP-42 Table 3.4-1	lbs/Hp-hr	0.30	0.08	0.30	0.08
PM10 (3)	0.0004011	AP-42 Table 3.4-2	lbs/Hp-hr	0.17	0.04	0.17	0.04
PM2.5 (3)	0.0003892	AP-42 Table 3.4-2	lbs/Hp-hr	0.17	0.04	0.17	0.04
SO2	0.004045	AP-42 Table 3.4-1	lbs/Hp-hr	1.74	0.43	1.74	0.43
NO <sub>x</sub> (1)	0.024	AP-42 Table 3.4-1	lbs/Hp-hr	10.32	2.58	5.59	1.40
VOC	0.000705	AP-42 Table 3.4-1	lbs/Hp-hr	0.30	0.08	0.30	0.08
CO	0.0055	AP-42 Table 3.4-1	lbs/Hp-hr	2.37	0.59	2.37	0.59
Benzene (3)	5.43E-06	AP-42 Table 3.4-3	lbs/Hp-hr	2.34E-03	5.84E-04	0.00	5.84E-04
Toluene (3)	1.97E-06	AP-42 Table 3.4-3	lbs/Hp-hr	8.46E-04	2.11E-04	0.00	2.11E-04
Xylene (3)	1.35E-06	AP-42 Table 3.4-3	lbs/Hp-hr	5.81E-04	1.45E-04	0.00	1.45E-04
Formaldehyde (3)	5.52E-07	AP-42 Table 3.4-3	lbs/Hp-hr	2.37E-04	5.94E-05	0.00	5.94E-05
Acetaldehyde (3)	1.76E-07	AP-42 Table 3.4-3	lbs/Hp-hr	7.59E-05	1.90E-05	0.00	1.90E-05
Acrolein (3)	5.52E-08	AP-42 Table 3.4-3	lbs/Hp-hr	2.37E-05	5.93E-06	0.00	5.93E-06
Total PAH (3)	1.48E-06	AP-42 Table 3.4-4	lbs/Hp-hr	6.38E-04	1.60E-04	0.00	1.60E-04
CO2	1.16E+00	AP-42 Table 3.4-1	lbs/Hp-hr	498.8	124.7	498.80	124.7
CH4 (4)	6.35E-05	40 CFR Part 98	lbs/Hp-hr	2.73E-02	6.82E-03	0.03	6.82E-03
N2O (4)	9.30E-06	40 CFR Part 98	lbs/Hp-hr	4.00E-03	1.00E-03	0.00	1.00E-03
				HAPs	5.92E-01	5.92E-01	

(1) NO<sub>x</sub> emission factor: uncontrolled = 0.024 lb/hp-hr, controlled by ignition timing retard = 0.013 lb/hp-hr

(2) PAH = Polyaromatic Hydrocarbon (PAHs are considered HAPs, since they are considered Polycyclic Organic Matter)

(3) Emission factors in lb/hp-hr were calculated using emission factors in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu/ hp-hr .

**Appendix A: Emissions Calculations  
Emergency ENG-4 Emissions  
Reciprocating Internal Combustion Engines - Natural Gas**

**Company Name: Duke Energy Indiana, LLC - Cayuga Generating Station  
Address City IN Zip: 3300 N SR 63, Cayuga, Indiana 47928  
Permit Number: 165-47094-00001  
Reviewer: Christopher Chin**

Emissions Unit	Emergency	ENG-4
Output Horsepower Rating (hp)		67.0
Maximum Hours Operated per Year		500
Potential Throughput (hp-hr/yr)		33,500
Sulfur Content (S) of Fuel (% by weight)		0.500

Pollutant	Emissions Factor	Source	Unit	Uncontrolled PTE		Controlled PTE	
				lbs/hr	tons/yr	lbs/hr	tons/yr
PM	0.0007	AP-42 Table 3.4-1	lbs/Hp-hr	0.05	0.01	0.05	0.01
PM10 (3)	0.0004011	AP-42 Table 3.4-2	lbs/Hp-hr	0.03	0.01	0.03	0.01
PM2.5 (3)	0.0003892	AP-42 Table 3.4-2	lbs/Hp-hr	0.03	0.01	0.03	0.01
SO2	0.004045	AP-42 Table 3.4-1	lbs/Hp-hr	0.27	0.07	0.27	0.07
NO <sub>x</sub> (1)	0.024	AP-42 Table 3.4-1	lbs/Hp-hr	1.61	0.40	0.87	0.22
VOC	0.000705	AP-42 Table 3.4-1	lbs/Hp-hr	0.05	0.01	0.05	0.01
CO	0.0055	AP-42 Table 3.4-1	lbs/Hp-hr	0.37	0.09	0.37	0.09
Benzene (3)	5.43E-06	AP-42 Table 3.4-3	lbs/Hp-hr	3.64E-04	9.10E-05	0.00	9.10E-05
Toluene (3)	1.97E-06	AP-42 Table 3.4-3	lbs/Hp-hr	1.32E-04	3.29E-05	0.00	3.29E-05
Xylene (3)	1.35E-06	AP-42 Table 3.4-3	lbs/Hp-hr	9.05E-05	2.26E-05	0.00	2.26E-05
Formaldehyde (3)	5.52E-07	AP-42 Table 3.4-3	lbs/Hp-hr	3.70E-05	9.25E-06	0.00	9.25E-06
Acetaldehyde (3)	1.76E-07	AP-42 Table 3.4-3	lbs/Hp-hr	1.18E-05	2.95E-06	0.00	2.95E-06
Acrolein (3)	5.52E-08	AP-42 Table 3.4-3	lbs/Hp-hr	3.70E-06	9.24E-07	0.00	9.24E-07
Total PAH (3)	1.48E-06	AP-42 Table 3.4-4	lbs/Hp-hr	9.94E-05	2.49E-05	0.00	2.49E-05
CO2	1.16E+00	AP-42 Table 3.4-1	lbs/Hp-hr	77.72	19.43	77.72	19.43
CH4 (4)	6.35E-05	40 CFR Part 98	lbs/Hp-hr	4.25E-03	1.06E-03	0.00	1.06E-03
N2O (4)	9.30E-06	40 CFR Part 98	lbs/Hp-hr	6.23E-04	1.56E-04	0.00	1.56E-04
				HAPs	9.23E-02	9.23E-02	

(1) NO<sub>x</sub> emission factor: uncontrolled = 0.024 lb/hp-hr, controlled by ignition timing retard = 0.013 lb/hp-hr

(2) PAH = Polyaromatic Hydrocarbon (PAHs are considered HAPs, since they are considered Polycyclic Organic Matter)

(3) Emission factors in lb/hp-hr were calculated using emission factors in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu/ hp-hr .

**Appendix A: Emission Calculations**  
**Reciprocating Internal Combustion Engines - Natural Gas**  
**4-Stroke Rich-Burn (4SRB) Engines**

**Company Name:** Duke Energy Indiana, LLC - Cayuga Generating Station  
**Source Address:** 3300 N SR 63, Cayuga, Indiana 47928  
**Permit Number:** 165-47094-00001  
**Reviewer:** Christopher Chin

Maximum Output Horsepower Rating (hp)	229
Brake Specific Fuel Consumption (BSFC) (Btu/hp-hr) **	7600
Maximum Hours Operated per Year (hr/yr)	500
Potential Fuel Usage (MMBtu/yr)	870
High Heat Value (MMBtu/MMscf)	1020
Potential Fuel Usage (MMcf/yr)	0.85

Criteria Pollutants	Pollutant						
	PM*	PM10*	PM2.5*	SO2	NOx	VOC	CO
Emission Factor (lb/MMBtu)	9.50E-03	1.94E-02	1.94E-02	5.88E-04	2.21E+00	2.96E-02	3.72E+00
Potential Emissions (tons/yr)	0.0041	0.01	0.01	0.000	0.96	0.01	1.62

\*PM emission factor is for filterable PM-10. PM10 emission factor is filterable PM10 + condensable PM.

\*\*PM2.5 emission factor is filterable PM2.5 + condensable PM.

\*\*Engine specification sheet did not provide Brake Specific Fuel Consumption (BSFC) value so a conservative value of 7600 Btu/hr-hr is used for engines between 80-1340 hp.  
 Note: Table and emission factors are for natural gas because none are currently available for liquid propane

**Hazardous Air Pollutants (HAPs)**

Pollutant	Emission Factor (lb/MMBtu)	Potential Emissions (tons/yr)
Acetaldehyde	2.79E-03	0.001
Acrolein	2.63E-03	0.001
Benzene	1.58E-03	0.001
1,3-Butadiene	6.63E-04	0.000
Formaldehyde	2.05E-02	0.009
Methanol	3.06E-03	0.001
Total PAH***	1.41E-04	0.000
Toluene	5.58E-04	0.000
Xylene	1.95E-04	0.000
<b>Total</b>		<b>0.01</b>

HAP pollutants consist of the nine highest HAPs included in AP-42 Table 3.2-3.

\*\*\*PAH = Polyaromatic Hydrocarbon (PAHs are considered HAPs, since they are considered Polycyclic Organic Matter)

**Methodology**

Emission Factors are from AP-42 (Supplement F, July 2000), Table 3.2-3

Potential Fuel Usage (MMBtu/yr) = [Maximum Output Horsepower Rating (hp)] \* [Brake Specific Fuel Consumption (Btu/hp-hr)] \* [Maximum Hours Operated per Year (hr/yr)] / [1000000 Btu/MMBtu]

Potential Emissions (tons/yr) = [Potential Fuel Usage (MMBtu/yr)] \* [Emission Factor (lb/MMBtu)] / [2000 lb/ton]

**Appendix A: Emissions Calculations  
Fugitive Emissions from Truck Traffic**

**Company Name: Duke Energy Indiana, LLC - Cayuga Generating Station**  
**Address City IN Zip: 3300 N SR 63, Cayuga, Indiana 47928**  
**Permit Number: 165-47094-00001**  
**Reviewer: Christopher Chin**

Description of Materials Delivered by Truck	Truck Capacity (tons)	Material Loaded Per Year	# Trucks	Paved On-way Miles/Trip	Unpaved On-way Miles/Trip	Paved One -way VMT (miles)	Unpaved One -way VMT (miles)
Truck Delivery of Coal	48.5	3,949,884.0	81,440.9	1.0	0.1	81,441	8,144
Truck Delivery of Limestone	20	509,000.0	25,450.0	1.0	0.1	25,450	2,545
FSS to Landfill*	20	736,567.0	36,828.4	1.27	0.1	46,772	3,683
Bottom Ash to Landfill	20	78,997.7	3,949.9	1	0.1	3,950	395
Gypsum to Landfill	20	900,528.0	45,026.4	1.5	0.1	67,540	4,503
(DSI) Hydrated Lime Delivery*	20	41,172.0	2,058.6	1.20	0	2,470	-
Limestone AS Mitigation	20	50,808.0	2,540.4	1.11	0	2,829	-
Lime for Fixation*	20	21,172.9	1,058.6	1.27	0	1,344	-
Ammonia Delivery*	20	12,448	622.4	1.10	0	685	-

## Notes:

Miles per trip includes truck traveling empty inside the facility and truck traveling full inside the facility.

Vehicle Miles Traveled (VMT) equals total miles truck traveled within the facility empty and full combined.

\*VMT based on Permit ID 165-32048-00001

Potential Emissions for Paved Road Ways								
Air Emission Source	Truck Capacity (tons)	Weight (W) of Full Truck (tons)	Weight (W) of Empty Truck (tons)	Avg Weight (W) of Truck (tons)	On-way VMT	PM Emission Factor (lb/VMT)	PM10 Emission Factor (lb/VMT)	PM2.5 Emission Factor (lb/VMT)
Truck Delivery of Coal	48.5	67	18.5	42.75	81441	0.2138	0.0428	0.0105
Truck Delivery of Limestone	20	32	12	22	25450	0.1086	0.0217	0.0053
FSS to Landfill	20	32	12	22	46772	0.1086	0.0217	0.0053
Bottom Ash to Landfill	20	32	12	22	3950	0.1086	0.0217	0.0053
Gypsum to Landfill (As needed)	20	32	12	22	67540	0.1086	0.0217	0.0053
(DSI) Hydrated Lime Delivery*	20	32	12	22	2470	0.1086	0.0217	0.0053
Limestone AS Mitigation	20	32	12	22	2829	0.1086	0.0217	0.0053
Lime for Fixation	20	32	12	22	1344	0.1086	0.0217	0.0053
Ammonia Delivery	20	32	12	22	685	0.1086	0.0217	0.0053

**Appendix A: Emissions Calculations  
Fugitive Emissions from Truck Traffic**

**Company Name: Duke Energy Indiana, LLC - Cayuga Generating Station  
Address City IN Zip: 3300 N SR 63, Cayuga, Indiana 47928  
Permit Number: 165-47094-00001  
Reviewer: Christopher Chin**

Air Emission Source	Uncontrolled			Controlled		
	PM (tons/yr)	PM10 (tons/yr)	PM2.5 (tons/yr)	PM (tons/yr)	PM10 (tons/yr)	PM2.5 (tons/yr)
Truck Delivery of Coal	17.41	3.48	0.85	1.741	0.348	0.085
Truck Delivery of Limestone	2.76	0.55	0.14	0.276	0.055	0.014
FSS to Landfill	5.08	1.02	0.25	0.508	0.102	0.025
Bottom Ash to Landfill	0.43	0.09	0.02	0.043	0.009	0.002
Gypsum to Landfill (As needed)	7.33	1.47	0.36	0.733	0.147	0.036
(DSI) Hydrated Lime Delivery*	0.27	0.05	0.01	0.027	0.005	0.001
Limestone AS Mitigation	0.31	0.06	0.02	0.031	0.006	0.002
Lime for Fixation	0.15	0.03	0.01	0.015	0.003	0.001
Ammonia Delivery	0.07	0.01	0.00	0.007	0.001	0.0004
<b>Total</b>	<b>33.81</b>	<b>6.76</b>	<b>1.66</b>	<b>3.38</b>	<b>0.68</b>	<b>0.17</b>

**Calculation Method:**

Unmitigated Emission Factor,  $E_f = [k * (sL)^{0.91} * (W)^{1.02}]$  (Equation 1 from AP-42 13.2.1)

where k =

PM	PM10	PM2.5
0.011	0.0022	0.00054
sL = 0.6	0.6	0.6

k = particle size multiplier (AP-42 Table 13.2.1-1)  
sL = silt content paved roadways

Taking natural mitigation due to precipitation into consideration, Mitigated Emission Factor,  $E_{ext} = E_f * [1 - (p/4N)]$  (Equation 2 from AP-42 13.2.1)

Mitigated Emission Factor,  $E_{ext} = E_f * [1 - (p/4N)]$   
where p = 120 days of rain greater than or equal to 0.01 inches (see Fig. 13.2.1-2)  
N = 365 days per year

Dust Control Efficiency =

PM	PM10	PM2.5
90%	90%	90%

Fugitive dust plan under CCP rule (water roadways, other dust suppression activities as needed)

Potential Emissions for Unpaved Road Ways								
Air Emission Source	Truck Capacity (tons)	Weight of Full Truck (tons)	Weight of Empty Truck	Avg Weight of Truck (tons)	On-way VMT	PM Emission	PM10 Emission	PM2.5 Emission
Truck Delivery of Coal	48.5	67	18.5	42.75	8144	1.7376	0.3475	0.0853
FSS to Landfill	20	32	12	22	3683	0.8824	0.1765	0.0433
Bottom Ash to Landfill	20	32	12	22	395	0.8824	0.1765	0.0433
Gypsum to Landfill	20	32	12	22	4503	0.8824	0.1765	0.0433



**Appendix A: Emissions Calculations  
Fugitive Emissions from Truck Traffic**

**Company Name: Duke Energy Indiana, LLC - Cayuga Generating Station**  
**Address City IN Zip: 3300 N SR 63, Cayuga, Indiana 47928**  
**Permit Number: 165-47094-00001**  
**Reviewer: Christopher Chin**

Air Emission Source	Uncontrolled			Controlled		
	PM (tons/yr)	PM10 (tons/yr)	PM2.5 (tons/yr)	PM (tons/yr)	PM10 (tons/yr)	PM2.5 (tons/yr)
Truck Delivery of Coal	14.15	2.83	0.69	1.42	0.28	0.07
FSS to Landfill	3.25	0.65	0.16	0.32	0.06	0.02
Bottom Ash to Landfill	0.35	0.07	0.02	0.03	0.01	0.00
Gypsum to Landfill	3.97	0.79	0.20	0.40	0.08	0.02
<b>Total</b>	<b>17.4</b>	<b>3.5</b>	<b>0.9</b>	<b>1.7</b>	<b>0.3</b>	<b>0.1</b>

**Calculation Method:**

Unmitigated Emission Factor,  $E_f = [k * (sL)^{0.91} * (W)^{1.02}]$  (Equation 1 from AP-42 13.2.1)

where k =	PM	PM10	PM2.5
sL =	0.011	0.0022	0.00054
	6	6	6

k = particle size multiplier (AP-42 Table 13.2.1-1)

sL = silt loading value for paved roads at iron and steel production facilities - Table 13.2.1-3)

Taking natural mitigation due to precipitation into consideration, Mitigated Emission Factor,  $E_{ext} = E * [1 - (p/4N)]$  (Equation 2 from AP-42 13.2.1)

Mitigated Emission Factor,  $E_{ext} = E_f * [1 - (p/4N)]$

where p = 120 days of rain greater than or equal to 0.01 inches (see Fig. 13.2.1-2)

N = 365 days per year

Dust Control Efficiency =	PM	PM10	PM2.5
	90%	90%	90%

Fugitive dust plan under CCP rule (water roadways, other dust suppression activities as needed)

Total Controlled and Uncontrolled Emissions from Paved and Unpaved Roads (tons/yr)						
Description of Materials Delivered by Truck	Uncontrolled			Controlled		
	PM	PM10	PM2.5	PM	PM10	PM2.5
Truck Delivery of Coal	31.5601	6.3120	1.5493	3.1560	0.6312	0.1549
Truck Delivery of Limestone	2.7628	0.5526	0.1356	0.2763	0.0553	0.0136
FSS to Landfill	8.3270	1.6654	0.4088	0.8327	0.1665	0.0409
Bottom Ash to Landfill	0.7773	0.1555	0.0382	0.0777	0.0155	0.0038
Gypsum to Landfill	11.3049	2.2610	0.5550	1.1305	0.2261	0.0555
(DSI) Hydrated Lime Delivery	0.2682	0.0536	0.0132	0.0268	0.0054	0.0013
Limestone AS Mitigation	0.3071	0.0614	0.0151	0.0307	0.0061	0.0015
Lime for Fixation	0.1460	0.0292	0.0072	0.0146	0.0029	0.0007
Ammonia Delivery	0.0743	0.0149	0.0036	0.0074	0.0015	0.0004
<b>Total</b>	<b>55.5276</b>	<b>11.1055</b>	<b>2.7259</b>	<b>5.5528</b>	<b>1.1106</b>	<b>0.2726</b>

**Appendix A: Emissions Calculations**  
**Emissions from Storage Piles due to Wind Erosion**

**Company Name: Duke Energy Indiana, LLC - Cayuga Generating Station**  
**Address City IN Zip: 3300 N SR 63, Cayuga, Indiana 47928**  
**Permit Number: 165-47094-00001**  
**Reviewer: Christopher Chin**

Description	Surface Area (m <sup>2</sup> )	Emission Factors			Potential to Emit		
		PM (g/m <sup>2</sup> )	PM <sub>10</sub> (g/m <sup>2</sup> )	PM <sub>2.5</sub> (g/m <sup>2</sup> )	PM (tons/yr)	PM <sub>10</sub> (tons/yr)	PM <sub>2.5</sub> (tons/yr)
Wind Erosion from Active Coal	47,155	677.2	338.6	50.8	8.80	4.40	0.66
Fixated Material Storage Pile	566	677.2	338.6	50.8	0.11	0.05	0.01
Active Area Landfill	12,200	677.2	338.6	50.8	2.28	1.14	0.17
Limestone	1,734	677.2	338.6	50.8	0.32	0.16	0.02
<b>Total</b>					<b>8.80</b>	<b>4.40</b>	<b>0.66</b>

**Methodology**

Emission factors are based on AP 42, Chapter 13.2.5-3, "Industrial Wind Erosion", 4th Edition, Equations 2 and 3.

	k	u <sub>t</sub>	u*	P	N	Factor
PM	1	1.12	1.18	1.86	365	677.2
PM10	0.5	1.12	1.18	1.86	365	338.6
PM2.5	0.075	1.12	1.18	1.86	365	50.8

$$P_i = 58 (u^* - u_t)^2 + 25 (u^* - u_t)$$

$$u^* = 0.053 u_{10}$$

N = number of disturbances per year = 365 [Reference: Subsection 13.2.5.3 in AP 42, N= 365 for a surface

P = erosion potential corresponding to the observed (or probable) fastest mile of wind for the ith period between

U<sub>10</sub> = fastest mile of reference anemometer for period between disturbances (m/s) = 22.35

U<sub>t</sub> = Frictional Velocity was obtained from AP-42 Table 13.2.5-2.

Pile Dimensions	Landfill <sup>1</sup>	Coal <sup>1</sup>	LS <sup>2</sup>	FSS <sup>2</sup>
Height	-	19	16	9
Width	-	182	-	-
Length	-	256	-	-
Diameter	-	-	42	24
Radius	-	122	21	12
Area	12200	47155	1734	566

<sup>1</sup> Title V Application

<sup>2</sup> Pile height assume 37 degree repose, H = 0.37679\* D

**Appendix A: Emissions Calculations**  
**Fugitive Emissions from Heavy Vehicle Traffic on Piles**

**Company Name: Duke Energy Indiana, LLC - Cayuga Generating Station**  
**Address City IN Zip: 3300 N SR 63, Cayuga, Indiana 47928**  
**Permit Number: 165-47094-00001**  
**Reviewer: Christopher Chin**

Source	Control	CE	PTE Uncontrolled			PTE Controlled		
			PM	PM10	PM2.5	PM	PM10	PM2.5
Gypsum Pile - Front End Loader	Wet Suppression	50%	1.98	0.53	0.05	0.990	0.267	0.027
Coal Pile - Dozer	Wet Suppression	50%	17.00	4.59	0.46	8.502	2.295	0.230
Limestone Pile - Dozer	Wet Suppression	50%	1.41	0.38	0.04	0.703	0.190	0.019
Landfill - Dozer	30% Moisture	90%	17.00	4.59	0.46	1.700	0.459	0.046
FSS Pile - Front End Loader	30% Moisture	90%	15.74	4.25	0.42	1.574	0.425	0.042
			<b>53.13</b>	<b>14.34</b>	<b>1.43</b>	<b>13.47</b>	<b>3.64</b>	<b>0.36</b>

Front-end loader and Dozer traffic on the pile, estimated using unpaved road way emissions factor

Source	Vehicle Weight (tons)	Annual VMT	PM lbs/VMT	PM10 lbs/VMT	PM2.5 lbs/VMT
Gypsum Pile - Front End Loader*	25	720	5.50	1.48	0.15
Coal Pile - Dozer**	53.8	4,380	7.76	2.10	0.21
Limestone Pile - Dozer*	53.8	362	7.76	2.10	0.21
Landfill - Dozer **	53.8	4380	7.76	2.10	0.21
FSS Pile - Front End Loader*	25	5724	5.50	1.48	0.15

\* VMT based 165-27260-00001

\*\* VMT based on vehicle speed of 3 mph, operating time of 4 hr/day and 356 days per year.

Methodology:

AP-42, Chapter 13.2.2 - Unpaved Roads (11/06), the PM/PM10 emission factors from the traffic on

$$E = \frac{k \times (s/12)^a \times (w/3)^b \times (365-P)}{365}$$

Description	Variable	PM	PM10	PM2.5
surface material silt content (%) =	s	6.4	6.4	6.4
empirical constants =	k	4.9	1.5	0.15
empirical constants =	a	0.7	0.9	0.9
empirical constants =	b	0.45	0.45	0.45
number of precipitation days =	p	120	120	120

**Appendix A: Emissions Calculations  
Throughput Data**

**Company Name:** Duke Energy Indiana, LLC - Cayuga Generating Station  
**Address City IN Zip:** 3300 N SR 63, Cayuga, Indiana 47928  
**Permit Number:** 165-47094-00001  
**Reviewer:** Christopher Chin

Coal Unit 1	1974942.00	Max Firing rate 8760 hr/yr	Estimated
Coal Unit 2	1974942.00	Max Firing rate 8760 hr/yr	Estimated
Coal Receiving	3949884.00	Total usage	Estimated
Ash	394988.40	Assume 10% Ash	Estimated
Fly Ash	315990.72	Assume 80% FA	Estimated
Bottom Ash	78997.68	Assume 20% BA	Estimated
Limestone	509000.00	Limited PTE	Permitted
Gypsum	900528.00	Limited PTE	Permitted
FSS (excluding Gypsum)	886,884	FSS 30% moisture	Permitted
FSS (including Gypsum)	1,500,114	FSS 30% moisture	
Hydrated Lime	35040.00	DSI SO3 Mitigation	Permitted
Limestone	35916.00	AS Mitigation	Permitted
Lime	30584.84	Fixation	Permitted