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**§ 63.9982**

Citation	Subject	Applies to Subpart TTTT	Explanation
63.3	Units and Abbreviations	Yes.	
63.4	Prohibited Activities	Yes.	
63.5	Construction and Reconstruction	Yes.	
63.6(a)–(g)	Compliance with Standards and Maintenance Requirements.	Yes.	
63.6(h)	Determining Compliance with Opacity and Visible Emission Standards.	No.	
63.6(i)–(j)	Extension of Compliance and Presidential Compliance Exemption.	Yes.	
63.7(a)(1)–(2)	Applicability and Performance Test Dates.	No	Subpart TTTT specifies performance test applicability and dates.
63.7(a)(3), (b)–(h)	Performance Testing Requirements.	Yes.	
63.8 except for (a)(4),(c)(4), and (f)(6).	Monitoring Requirements	Yes.	
63.8(a)(4)	Additional Monitoring Requirements for Control Devices in § 63.11.	No	Subpart TTTT does not require flares.
63.8(c)(4)	Continuous Monitoring System Requirements.	No	Subpart TTTT specifies requirements for operation of CMS.
63.8(f)(6)	Relative Accuracy Test Alternative (RATA).	No	Subpart TTTT does not require continuous emission monitoring systems.
63.9	Notification Requirements	Yes.	
63.9(g)(5)	Data Reduction	No	Subpart TTTT specifies data reduction requirements.
63.10 except for (b)(2)(xiii) and (c)(7)–(8).	Recordkeeping and Reporting Requirements.	Yes.	
63.10(b)(2)(xiii)	Continuous Monitoring System (CMS) Records for RATA Alternative.	No	Subpart TTTT does not require continuous emission monitoring systems.
63.10(c)(7)–(8)	Records of Excess Emissions and Parameter Monitoring Accedences for CMS.	No	Subpart TTTT specifies record-keeping requirements.
63.11	Control Device Requirements	No	Subpart TTTT does not require flares.
63.12	State Authority and Delegations	Yes.	
63.13–63.15	Addresses, Incorporation by Reference, Availability of Information.	Yes.	

**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.

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(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

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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 by-

pass 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 in-

stallations, 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

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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 emis-

sion 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 cer-

tain 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  $E_{hj}$  in Equation 19–19 must be in the same units of measure as the applicable HCl or HF emission limit in Table 1 or 2 to this subpart).

(2) For affected coal-fired or solid oil-derived fuel-fired EGUs that demonstrate compliance with the applicable emission limits for total non-mercury HAP metals, individual non-mercury HAP metals, total HAP metals, individual HAP metals, or filterable PM listed in Table 1 or 2 to this subpart using initial performance testing

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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.

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(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).

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(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 de-

termine 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 ( $\mu\text{g}/\text{scm}$ ) 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 ≥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 ≥ 8,300 Btu/lb” sub-

category, 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 ≥ 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<sub>m</sub> = Maximum Weighted Average Emission Rate in terms of lb/heat input or lb/gross output,

Herm<sub>i,j</sub> = hourly emission rate (e.g., lb/MMBtu, lb/MWh) from CEMS or sorbent trap monitoring as determined during the

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initial compliance determination from EGU j.  
 Rmm<sub>j</sub> = 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<sub>k</sub> = Emissions rate (lb/MMBTU or lb/MWh) as determined during the initial compliance determination of EGU k.  
 Rmt<sub>k</sub> = 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.

$$WAER_m = \frac{\sum \left[ (\sum_{j=1}^p Herm_{i,j}) \times Smm_j \times Cfm_{j,j} \right] + \sum_{k=1}^m Ter_k \times Smt_k \times Cft_k}{\sum \left[ \sum_{j=1}^p Smm_j \times Cfm_j \right] + \sum_{k=1}^m Smt_k \times Cft_k} \quad (Eq. 1b)$$

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<sub>i</sub> = steam generation in units of pounds from unit i that uses CEMS for the preceding 30-group boiler operating days,

Cfm<sub>i</sub> = 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<sub>i</sub> = steam generation in units of pounds from unit i that uses emissions testing, and  
 Cft<sub>i</sub> = 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<sub>i</sub> = Hourly emission rate from unit i’s Hg CEMS or Hg sorbent trap monitoring system for the preceding 90-group boiler operating days,

Rm<sub>i</sub> = 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<sub>i</sub> = Hourly emission rate from unit i’s Hg CEMS or Hg sorbent trap monitoring system for the preceding 90-group boiler operating days,

Sm<sub>i</sub> = 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<sub>i</sub> = 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

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included in the emissions averaging and from other units not included in the emissions averaging (e.g., in a different subcategory) or other non-affected 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 emis-

sions 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 ongoing 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.

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(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 non-exempt 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 (1)(3)(i) through (vi) of this section.

(5) You must operate and maintain the monitoring system according to the site-specific monitoring plan.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23404, Apr. 19, 2012; 78 FR 24086, Apr. 24, 2013; 79 FR 68789, Nov. 19, 2014; 81 FR 20185, Apr. 6, 2016; 85 FR 55758, Sept. 9, 2020]

**§ 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-

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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.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23404, Apr. 19, 2012; 79 FR 68790, Nov. 19, 2014; 81 FR 20186, Apr. 6, 2016; 85 FR 55759, Sept. 9, 2020]

### 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(1).

(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.

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(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 meas-

ure 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.

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

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 contin-

uous 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.

$$\text{30 boiler operating day average} = \frac{\sum_{i=1}^n Hp v_i}{n} \text{ (Eq. 9)}$$

Where:

Hpv<sub>i</sub> 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 per-

form 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 restart 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



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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

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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 semi-annual 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.

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(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,

$\bar{y}$  = 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.

$$O_n = \frac{1}{n} \sum_{i=1}^n X_i \quad (\text{Eq. 13})$$

Where:

$X_i$  = the PM CPMS data points for all runs  $i$ ,  
 $n$  = the number of data points, and  
 $O_n$  = 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 av-

erage 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

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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:

(I) 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;

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(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.



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(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

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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.

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(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.

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### 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.

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#### § 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. Indi-

vidual 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. Start-up 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.

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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). OR Total non-Hg HAP metals OR Individual HAP metals: ..... Antimony (Sb) ..... Arsenic (As) ..... Beryllium (Be) ..... Cadmium (Cd) ..... Chromium (Cr) ..... Cobalt (Co) ..... Lead (Pb) ..... Manganese (Mn) ..... Nickel (Ni) ..... Selenium (Se) .....	9.0E-2 lb/MWh <sup>1</sup> ..... OR 6.0E-2 lb/GWh ..... OR 8.0E-3 lb/GWh. 3.0E-3 lb/GWh. 6.0E-4 lb/GWh. 4.0E-4 lb/GWh. 7.0E-3 lb/GWh. 2.0E-3 lb/GWh. 2.0E-2 lb/GWh. 4.0E-3 lb/GWh. 4.0E-2 lb/GWh. 5.0E-2 lb/GWh.	Collect a minimum of 4 dscm per run.  Collect a minimum of 4 dscm per run.  Collect a minimum of 3 dscm per run.
	b. Hydrogen chloride (HCl)  OR Sulfur dioxide (SO <sub>2</sub> ) <sup>3</sup> .....	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.  SO <sub>2</sub> CEMS. Hg CEMS or sorbent trap monitoring system only.
2. Coal-fired units low rank virgin coal.	a. Filterable particulate matter (PM). OR Total non-Hg HAP metals OR Individual HAP metals: ..... Antimony (Sb) ..... Arsenic (As) ..... Beryllium (Be) ..... Cadmium (Cd) ..... Chromium (Cr) ..... Cobalt (Co) ..... Lead (Pb) ..... Manganese (Mn) ..... Nickel (Ni) ..... Selenium (Se) .....	9.0E-2 lb/MWh <sup>1</sup> ..... OR 6.0E-2 lb/GWh ..... OR 8.0E-3 lb/GWh. 3.0E-3 lb/GWh. 6.0E-4 lb/GWh. 4.0E-4 lb/GWh. 7.0E-3 lb/GWh. 2.0E-3 lb/GWh. 2.0E-2 lb/GWh. 4.0E-3 lb/GWh. 4.0E-2 lb/GWh. 5.0E-2 lb/GWh.	Collect a minimum of 4 dscm per run.  Collect a minimum of 4 dscm per run.  Collect a minimum of 3 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 . . .
3. IGCC unit	b. Hydrogen chloride (HCl)  OR Sulfur dioxide (SO <sub>2</sub> ) <sup>3</sup> c. Mercury (Hg)  a. Filterable particulate matter (PM). OR Total non-Hg HAP metals OR Individual HAP metals: Antimony (Sb) Arsenic (As) Beryllium (Be) Cadmium (Cd) Chromium (Cr) Cobalt (Co) Lead (Pb) Manganese (Mn) Nickel (Ni) Selenium (Se) b. Hydrogen chloride (HCl)  OR Sulfur dioxide (SO <sub>2</sub> ) <sup>3</sup> c. Mercury (Hg)	1.0E-2 lb/MWh  1.0 lb/MWh 4.0E-2 lb/GWh  7.0E-2 lb/MWh <sup>4</sup> 9.0E-2 lb/MWh <sup>5</sup> . OR 4.0E-1 lb/GWh OR 2.0E-2 lb/GWh. 2.0E-2 lb/GWh. 1.0E-3 lb/GWh. 2.0E-3 lb/GWh. 4.0E-2 lb/GWh. 4.0E-3 lb/GWh. 9.0E-3 lb/GWh. 2.0E-2 lb/GWh. 7.0E-2 lb/GWh. 3.0E-1 lb/GWh. 2.0E-3 lb/MWh  4.0E-1 lb/MWh 3.0E-3 lb/GWh 3.0E-1 lb/MWh <sup>1</sup>  OR 2.0E-4 lb/MWh OR 1.0E-2 lb/GWh. 3.0E-3 lb/GWh. 5.0E-4 lb/GWh. 2.0E-4 lb/GWh. 2.0E-2 lb/GWh. 3.0E-2 lb/GWh. 8.0E-3 lb/GWh. 2.0E-2 lb/GWh. 9.0E-2 lb/GWh. 2.0E-2 lb/GWh. 1.0E-4 lb/GWh  4.0E-4 lb/MWh  4.0E-4 lb/MWh  2.0E-1 lb/MWh <sup>1</sup>  OR	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.  SO <sub>2</sub> CEMS. Hg CEMS or sorbent trap monitoring system only. Collect a minimum of 1 dscm per run.  Collect a minimum of 1 dscm per run.  Collect a minimum of 2 dscm per run.  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.  SO <sub>2</sub> CEMS. Hg CEMS or sorbent trap monitoring system only. Collect a minimum of 1 dscm per run.  Collect a minimum of 2 dscm per run.  Collect a minimum of 2 dscm per run.  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 < ½ the standard. 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. 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. Collect a minimum of 1 dscm per run.
4. Liquid oil-fired unit—continental (excluding limited-use liquid oil-fired subcategory units).	a. Filterable particulate matter (PM).  OR Total HAP metals OR Individual HAP metals: Antimony (Sb) Arsenic (As) Beryllium (Be) Cadmium (Cd) Chromium (Cr) Cobalt (Co) Lead (Pb) Manganese (Mn) Nickel (Ni) Selenium (Se) Mercury (Hg)	3.0E-1 lb/MWh <sup>1</sup>  OR 2.0E-4 lb/MWh OR 1.0E-2 lb/GWh. 3.0E-3 lb/GWh. 5.0E-4 lb/GWh. 2.0E-4 lb/GWh. 2.0E-2 lb/GWh. 3.0E-2 lb/GWh. 8.0E-3 lb/GWh. 2.0E-2 lb/GWh. 9.0E-2 lb/GWh. 2.0E-2 lb/GWh. 1.0E-4 lb/GWh	Collect a minimum of 1 dscm per run.  Collect a minimum of 2 dscm per run.  Collect a minimum of 2 dscm per run.  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 < ½ the standard.
5. Liquid oil-fired unit—non-continental (excluding limited-use liquid oil-fired subcategory units).	b. Hydrogen chloride (HCl)  c. Hydrogen fluoride (HF)  a. Filterable particulate matter (PM).  OR	4.0E-4 lb/MWh  4.0E-4 lb/MWh  2.0E-1 lb/MWh <sup>1</sup>  OR	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. 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. Collect a minimum of 1 dscm per run.

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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 . . .
6. Solid oil-derived fuel-fired unit.	Total HAP metals ..... OR ..... Individual HAP metals: ..... Antimony (Sb) ..... Arsenic (As) ..... Beryllium (Be) ..... Cadmium (Cd) ..... Chromium (Cr) ..... Cobalt (Co) ..... Lead (Pb) ..... Manganese (Mn) ..... Nickel (Ni) ..... Selenium (Se) ..... Mercury (Hg) .....	7.0E-3 lb/MWh ..... OR ..... 8.0E-3 lb/GWh. 6.0E-2 lb/GWh. 2.0E-3 lb/GWh. 2.0E-3 lb/GWh. 2.0E-2 lb/GWh. 3.0E-1 lb/GWh. 3.0E-2 lb/GWh. 1.0E-1 lb/GWh. 4.1E0 lb/GWh. 2.0E-2 lb/GWh. 4.0E-4 lb/GWh .....	Collect a minimum of 1 dscm per run.  Collect a minimum of 3 dscm per run.         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.
	a. Filterable particulate matter (PM).	3.0E-2 lb/MWh <sup>1</sup> .....	Collect a minimum of 1 dscm per run.
	OR .....	OR .....	
	Total non-Hg HAP metals	6.0E-1 lb/GWh .....	Collect a minimum of 1 dscm per run.
	OR .....	OR .....	
	Individual HAP metals: .....		Collect a minimum of 3 dscm per run.
	Antimony (Sb) .....	8.0E-3 lb/GWh.	
	Arsenic (As) .....	3.0E-3 lb/GWh.	
	Beryllium (Be) .....	6.0E-4 lb/GWh.	
	Cadmium (Cd) .....	7.0E-4 lb/GWh.	
	Chromium (Cr) .....	6.0E-3 lb/GWh.	
	Cobalt (Co) .....	2.0E-3 lb/GWh.	
	Lead (Pb) .....	2.0E-2 lb/GWh.	
Manganese (Mn) .....	7.0E-3 lb/GWh.		
Nickel (Ni) .....	4.0E-2 lb/GWh.		
Selenium (Se) .....	6.0E-3 lb/GWh.		
b. Hydrogen chloride (HCl)	4.0E-4 lb/MWh .....	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348-03 <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.

[81 FR 20190, Apr. 6, 2016]

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>

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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). OR Total non-Hg HAP metals. OR Individual HAP metals: Antimony (Sb) ..... Arsenic (As) ..... Beryllium (Be) ..... Cadmium (Cd) ..... Chromium (Cr) ..... Cobalt (Co) ..... Lead (Pb) ..... Manganese (Mn) ..... Nickel (Ni) ..... Selenium (Se) ..... b. Hydrogen chloride (HCl). OR Sulfur dioxide (SO <sub>2</sub> ) <sup>4</sup> ... c. Mercury (Hg) .....	3.0E-2 lb/MMBtu or 3.0E-1 lb/MWh <sup>2</sup> . OR 5.0E-5 lb/MMBtu or 5.0E-1 lb/GWh. OR ..... 8.0E-1 lb/TBtu or 8.0E-3 lb/GWh. 1.1E0 lb/TBtu or 2.0E-2 lb/GWh. 2.0E-1 lb/TBtu or 2.0E-3 lb/GWh. 3.0E-1 lb/TBtu or 3.0E-3 lb/GWh. 2.8E0 lb/TBtu or 3.0E-2 lb/GWh. 8.0E-1 lb/TBtu or 8.0E-3 lb/GWh. 1.2E0 lb/TBtu or 2.0E-2 lb/GWh. 4.0E0 lb/TBtu or 5.0E-2 lb/GWh. 3.5E0 lb/TBtu or 4.0E-2 lb/GWh. 5.0E0 lb/TBtu or 6.0E-2 lb/GWh. 2.0E-3 lb/MMBtu or 2.0E-2 lb/MWh. OR 2.0E-1 lb/MMBtu or 1.5E0 lb/MWh. 1.2E0 lb/TBtu or 1.3E-2 lb/GWh. OR 1.0E0 lb/TBtu or 1.1E-2 lb/GWh.	Collect a minimum of 1 dscm per run. Collect a minimum of 1 dscm per run. Collect a minimum of 3 dscm per run. 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. SO <sub>2</sub> CEMS. 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. 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). OR Total non-Hg HAP metals. OR Individual HAP metals: Antimony (Sb) ..... Arsenic (As) ..... Beryllium (Be) ..... Cadmium (Cd) .....	3.0E-2 lb/MMBtu or 3.0E-1 lb/MWh <sup>2</sup> . OR 5.0E-5 lb/MMBtu or 5.0E-1 lb/GWh. OR ..... 8.0E-1 lb/TBtu or 8.0E-3 lb/GWh. 1.1E0 lb/TBtu or 2.0E-2 lb/GWh. 2.0E-1 lb/TBtu or 2.0E-3 lb/GWh. 3.0E-1 lb/TBtu or 3.0E-3 lb/GWh.	Collect a minimum of 1 dscm per run. Collect a minimum of 1 dscm per run. Collect a minimum of 3 dscm per run.



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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 . . . .
	Chromium (Cr) ..... Cobalt (Co) ..... Lead (Pb) ..... Manganese (Mn) ..... Nickel (Ni) ..... Selenium (Se) ..... b. Hydrogen chloride (HCl).  OR Sulfur dioxide (SO <sub>2</sub> ) <sup>4</sup> ... c. Mercury (Hg) .....	2.8E0 lb/TBtu or 3.0E-2 lb/GWh. 8.0E-1 lb/TBtu or 8.0E-3 lb/GWh. 1.2E0 lb/TBtu or 2.0E-2 lb/GWh. 4.0E0 lb/TBtu or 5.0E-2 lb/GWh. 3.5E0 lb/TBtu or 4.0E-2 lb/GWh. 5.0E0 lb/TBtu or 6.0E-2 lb/GWh. 2.0E-3 lb/MMBtu or 2.0E-2 lb/MWh.  2.0E-1 lb/MMBtu or 1.5E0 lb/MWh. 4.0E0 lb/TBtu or 4.0E-2 lb/GWh.	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.  SO <sub>2</sub> CEMS. 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). OR Total non-Hg HAP metals. OR Individual HAP metals: ..... Antimony (Sb) ..... Arsenic (As) ..... Beryllium (Be) ..... Cadmium (Cd) ..... Chromium (Cr) ..... Cobalt (Co) ..... Lead (Pb) ..... Manganese (Mn) ..... Nickel (Ni) ..... Selenium (Se) ..... b. Hydrogen chloride (HCl).  c. Mercury (Hg) .....	4.0E-2 lb/MMBtu or 4.0E-1 lb/MWh <sup>2</sup> . OR 6.0E-5 lb/MMBtu or 5.0E-1 lb/GWh. OR ..... 1.4E0 lb/TBtu or 2.0E-2 lb/GWh. 1.5E0 lb/TBtu or 2.0E-2 lb/GWh. 1.0E-1 lb/TBtu or 1.0E-3 lb/GWh. 1.5E-1 lb/TBtu or 2.0E-3 lb/GWh. 2.9E0 lb/TBtu or 3.0E-2 lb/GWh. 1.2E0 lb/TBtu or 2.0E-2 lb/GWh. 1.9E+2 lb/TBtu or 1.8E0 lb/GWh. 2.5E0 lb/TBtu or 3.0E-2 lb/GWh. 6.5E0 lb/TBtu or 7.0E-2 lb/GWh. 2.2E+1 lb/TBtu or 3.0E-1 lb/GWh. 5.0E-4 lb/MMBtu or 5.0E-3 lb/MWh.  2.5E0 lb/TBtu or 3.0E-2 lb/GWh.	Collect a minimum of 1 dscm per run.  Collect a minimum of 1 dscm per run.  Collect a minimum of 2 dscm per run.  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. 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.

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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 . . .
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 Total HAP metals .....	OR 8.0E–4 lb/MMBtu or 8.0E–3 lb/MWh.	Collect a minimum of 1 dscm per run.
	OR Individual HAP metals:	OR	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 <sup>1/2</sup> 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.
	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 Total HAP metals .....	OR 6.0E–4 lb/MMBtu or 7.0E–3 lb/MWh.	Collect a minimum of 1 dscm per run.
	OR Individual HAP metals:	OR	Collect a minimum of 2 dscm per run.
	Antimony (Sb) .....	2.2E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Arsenic (As) .....	4.3E0 lb/TBtu or 8.0E–2 lb/GWh.	
	Beryllium (Be) .....	6.0E–1 lb/TBtu or 3.0E–3 lb/GWh.	
	Cadmium (Cd) .....	3.0E–1 lb/TBtu or 3.0E–3 lb/GWh.	
	Chromium (Cr) .....	3.1E+1 lb/TBtu or 3.0E–1 lb/GWh.	
	Cobalt (Co) .....	1.1E+2 lb/TBtu or 1.4E0 lb/GWh.	
	Lead (Pb) .....	4.9E0 lb/TBtu or 8.0E–2 lb/GWh.	
	Manganese (Mn) .....	2.0E+1 lb/TBtu or 3.0E–1 lb/GWh.	

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Pt. 63, Subpt. UUUUU, Table 2

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 . . . .
6. Solid oil-derived fuel-fired unit . . . . .	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.  b. Hydrogen chloride (HCl). 2.0E-4 lb/MMBtu or 2.0E-3 lb/MWh.  c. Hydrogen fluoride (HF). 6.0E-5 lb/MMBtu or 5.0E-4 lb/MWh.  a. Filterable particulate matter (PM). 8.0E-3 lb/MMBtu or 9.0E-2 lb/MWh <sup>2</sup> . OR Total non-Hg HAP metals. 4.0E-5 lb/MMBtu or 6.0E-1 lb/GWh. OR Individual HAP metals: ..... 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.  OR Sulfur dioxide (SO <sub>2</sub> ) <sup>4</sup> ... 3.0E-1 lb/MMBtu or 2.0E0 lb/MWh.  c. 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 <sup>1</sup>/sub>2 the standard.  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.  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.  Collect a minimum of 1 dscm per run.  Collect a minimum of 1 dscm per run.  Collect a minimum of 3 dscm per run.  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.  SO <sub>2</sub> CEMS.  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.	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be <sup>1</sup>/sub>2 the standard.  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.  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.  Collect a minimum of 1 dscm per run.  Collect a minimum of 1 dscm per run.  Collect a minimum of 3 dscm per run.  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.  SO <sub>2</sub> CEMS.  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.
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> . OR Total non-Hg HAP metals. 5.0E-5 lb/MMBtu or 5.0E-1 lb/GWh. OR Individual HAP metals: .....	Collect a minimum of 1 dscm per run.  Collect a minimum of 1 dscm per run.  Collect a minimum of 3 dscm per run.	Collect a minimum of 1 dscm per run.  Collect a minimum of 1 dscm per run.  Collect a minimum of 3 dscm per run.

Pt. 63, Subpt. UUUUU, Table 3

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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 . . . .
	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.
		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).

If your EGU is . . .	You must meet the following . . .
<p>3. A coal-fired, liquid oil-fired (excluding limited-use liquid oil-fired sub-category units), or solid oil-derived fuel-fired EGU during startup.</p>	<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> <p>(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.</p> <p>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).</p> <p>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.</p> <p>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.</p> <p>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.</p> <p>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.</p> <p>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).</p>
<p>4. A coal-fired, liquid oil-fired (excluding limited-use liquid oil-fired sub-category units), or solid oil-derived fuel-fired EGU during shutdown.</p>	<p>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.</p> <p>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.</p> <p>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.</p> <p>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.</p>

**Pt. 63, Subpt. UUUUU, Table 4**

**40 CFR Ch. I (7–1–21 Edition)**

If your EGU is . . .	You must meet the following . . .
	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).

[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 .....	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).

[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. b. Determine velocity and volumetric flow-rate of the stack gas. c. Determine oxygen and carbon dioxide concentrations of the stack gas. d. Measure the moisture content of the stack gas. e. Measure the filterable PM concentration.  f. Convert emissions concentration to lb/MMBtu or lb/MWh emissions rates.	Method 1 at appendix A–1 to part 60 of this chapter. Method 2, 2A, 2C, 2F, 2G or 2H at appendix A–1 or A–2 to part 60 of this chapter. Method 3A or 3B at appendix A–2 to part 60 of this chapter, or ANSI/ASME PTC 19.10–1981. <sup>3</sup> Method 4 at appendix A–3 to part 60 of this chapter. 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). 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	

<sup>1</sup>Regarding emissions data collected during periods of startup or shutdown, see §§ 63.10020(b) and (c) and 63.10021(h).



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40 CFR Ch. I (7-1-21 Edition)

3.e.1(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:

$$\text{Reported Result} = \frac{(\text{Measured Concentration in Stack})}{\%R} \times 100$$

and

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)
4. Mercury (Hg) .....	OR HCl and/or HF CEMS.  Emissions Testing  OR Hg CEMS .....  OR	f. Convert emissions concentration to lb/MMBtu or lb/MWh emissions rates.  OR a. Install, certify, operate, and maintain the HCl or HF CEMS. b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems. c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates.  a. Select sampling ports location and the number of traverse points.  b. Determine velocity and volumetric flow-rate of the stack gas.  c. Determine oxygen and carbon dioxide concentrations of the stack gas.  d. Measure the moisture content of the stack gas.  e. Measure the Hg emission concentration.  f. Convert emissions concentration to lb/TBtu or lb/GWh emission rates.  OR a. Install, certify, operate, and maintain the CEMS. b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems. c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/TBtu or lb/GWh emissions rates.  OR	(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. 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)).  Appendix B of this subpart.  Part 75 of this chapter and § 63.10010(a), (b), (c), and (d).  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)). Method 1 at appendix A-1 to part 60 of this chapter or Method 30B at Appendix A-8 for Method 30B point selection. Method 2, 2A, 2C, 2F, 2G or 2H at appendix A-1 or A-2 to part 60 of this chapter. Method 3A or 3B at appendix A-1 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981. <sup>3</sup> Method 4 at appendix A-3 to part 60 of this chapter. Method 30B at appendix A-8 to part 60 of this chapter, ASTM D6784, <sup>3</sup> or Method 29 at appendix A-8 to part 60 of this chapter; for Method 29, you must report the front half and back half results separately. 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)).  Sections 3.2.1 and 5.1 of appendix A of this subpart. Part 75 of this chapter and § 63.10010(a), (b), (c), and (d).  Section 6 of appendix A to this subpart.





Pt. 63, Subpt. UUUUU, Table 7

40 CFR Ch. I (7–1–21 Edition)

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 . . .
<ol style="list-style-type: none"> <li>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.</li> <li>2. PM CPMS to measure compliance with a parametric operating limit.</li> <li>3. Site-specific monitoring using CMS for liquid oil-fired EGUs for HCl and HF emission limit monitoring.</li> <li>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.</li> <li>5. Conducting periodic performance tune-ups of your EGU(s).</li> <li>6. Work practice standards for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs during startup.</li> <li>7. Work practice standards for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs during shutdown.</li> </ol>	<p>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.</p> <p>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.</p> <p>If applicable, by conducting the monitoring in accordance with an approved site-specific monitoring plan.</p> <p>Calculating the results of the testing in units of the applicable emissions standard.</p> <p>Conducting periodic performance tune-ups of your EGU(s), as specified in § 63.10021(e).</p> <p>Operating in accordance with Table 3.</p> <p>Operating in accordance with Table 3.</p>

[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]

You must submit the following reports . . .

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).  
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.  
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).

**Pt. 63, Subpt. UUUUU, Table 9**

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[In accordance with 40 CFR 63.10031, you must meet the following reporting requirements, as they apply to your compliance strategy]

You must submit the following reports . . .

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:

Citation	Subject	Applies to subpart UUUUU
§ 63.1	Applicability	Yes.
§ 63.2	Definitions	Yes. Additional terms defined in § 63.10042.
§ 63.3	Units and Abbreviations	Yes.
§ 63.4	Prohibited Activities and Circumvention.	Yes.
§ 63.5	Preconstruction Review and Notification Requirements.	Yes.
§ 63.6(a), (b)(1) 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.
§ 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.

Citation	Subject	Applies to subpart UUUUU
§ 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.
§ 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 specification.

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 appli-

cable 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 ( $\mu\text{g}/\text{dscm}$ ), 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 ( $\text{HgCl}_2$ ), and that meets the performance requirements of the "EPA Traceability Protocol for Qualification and Certification of Mercuric Chloride Gas Generators" or an interim version of that protocol.

3.1.6 *Calibration Gas* means a NIST-traceable gas standard containing a known concentration of elemental or oxidized Hg that is produced and certified in accordance with an EPA traceability protocol.

3.1.7 *Span Value* means a conservatively high estimate of the Hg concentrations to be measured by a CEMS. The span value of a Hg CEMS should be set to approximately twice the concentration corresponding to the emission standard, rounded off as appropriate (see section 3.2.1.4.2 of this appendix).

3.1.8 *Zero-Level Gas* means calibration gas containing a Hg concentration that is below the level detectable by the Hg gas analyzer in use.

3.1.9 *Low-Level Gas* means calibration gas with a concentration that is 20 to 30 percent of the span value.

3.1.10 *Mid-Level Gas* means calibration gas with a concentration that is 50 to 60 percent of the span value.

3.1.11 *High-Level Gas* means calibration gas with a concentration that is 80 to 100 percent of the span value.

3.1.12 *Calibration Error Test* means a test designed to assess the ability of a Hg CEMS to measure the concentrations of calibration gases accurately. A zero-level gas and an upscale gas are required for this test. For the upscale gas, either a mid-level gas or a high-level gas may be used, and the gas may either be an elemental or oxidized Hg standard.

3.1.13 *Linearity Check* means a test designed to determine whether the response of a Hg analyzer is linear across its measurement range. Three elemental Hg calibration gas standards (*i.e.*, low, mid, and high-level gases) are required for this test.

3.1.14 *System Integrity Check* means a test designed to assess the transport and measurement of oxidized Hg by a Hg CEMS. Oxidized Hg standards are used for this test. For a three-level system integrity check, low, mid, and high-level calibration gases are required. For a single-level check, either a mid-level gas or a high-level gas may be used.

3.1.15 *Cycle Time Test* means a test designed to measure the amount of time it takes for a Hg CEMS, while operating normally, to respond to a known step change in gas concentration. For this test, a zero gas and a high-level gas are required. The high-level gas may be either an elemental or an oxidized Hg standard.

3.1.16 *Relative Accuracy Test Audit* or *RATA* means a series of nine or more test runs, directly comparing readings from a Hg CEMS or sorbent trap monitoring system to measurements made with a reference stack test method. The relative accuracy (RA) of the monitoring system is expressed as the absolute mean difference between the monitoring system and reference method measurements plus the absolute value of the 2.5 percent error confidence coefficient, divided by the mean value of the reference method measurements.

3.1.17 *Unit Operating Hour* means a clock hour in which a unit combusts any fuel, either for part of the hour or for the entire hour.

3.1.18 *Stack Operating Hour* means a clock hour in which gases flow through a particular monitored stack or duct (either for part of the hour or for the entire hour), while the associated unit(s) are combusting fuel.

3.1.19 *Operating Day* means a calendar day in which a source combusts any fuel.

3.1.20 *Quality Assurance (QA) Operating Quarter* means a calendar quarter in which

there are at least 168 unit or stack operating hours (as defined in this section).

3.1.21 *Grace Period* means a specified number of unit or stack operating hours after the deadline for a required quality-assurance test of a continuous monitor has passed, in which the test may be performed and passed without loss of data.

3.2 *Continuous Monitoring Methods.*

3.2.1 *Hg CEMS.* A typical Hg CEMS is shown in Figure A-1. The CEMS in Figure A-1 is a dilution extractive system, which measures Hg concentration on a wet basis, and is the most commonly-used type of Hg CEMS. Other system designs may be used, provided that the CEMS meets the performance specifications in section 4.1.1 of this appendix.

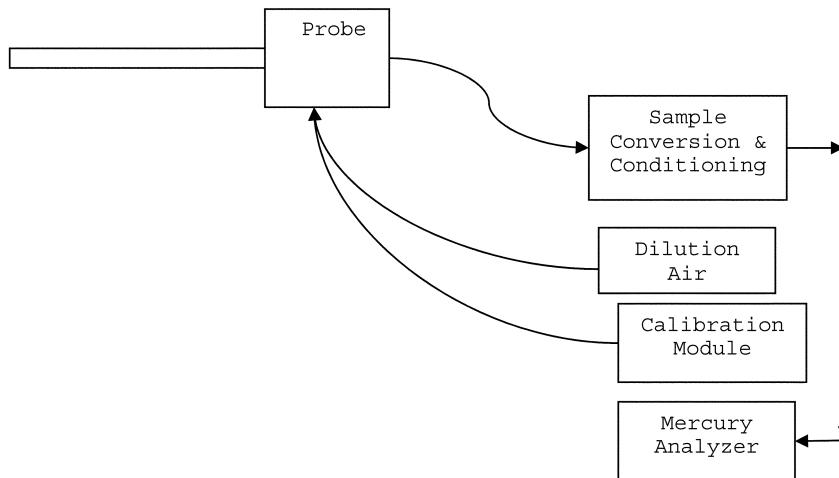


FIGURE A-1. TYPICAL MERCURY CEMS

3.2.1.1 *Equipment Specifications.*

3.2.1.1.1 *Materials of Construction.* All wetted sampling system components, including probe components prior to the point at which the calibration gas is introduced, must be chemically inert to all Hg species. Materials such as perfluoroalkoxy (PFA) Teflon™, quartz, and treated stainless steel (SS) are examples of such materials.

3.2.1.1.2 *Temperature Considerations.* All system components prior to the Hg<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}$ <sup>7</sup> .	$RM_{\text{avg}} < 2.5 \mu\text{g}/\text{scm}$
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  $|RM_{avg} - C_{avg}|$  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 measure-

ment sensitivity of a batch sampling type Hg CEMS for a specific application, you may petition the Administrator for approval of a time longer than 15 minutes between readings.

4.1.1.5 *Relative Accuracy Test Audit (RATA).* Perform the RATA of the Hg CEMS at normal load. Acceptable Hg reference methods for the RATA include ASTM D6784-02 (Reapproved 2008), “Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method)” (incorporated by reference, see §63.14) and Methods 29, 30A, and 30B in appendix A-8 to part 60 of this chapter. When Method 29 or ASTM D6784-02 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 D6784-02 test run, calculate the relative deviation (RD) using Equation A-1 of this section, and assess the results as follows to validate the run. The RD must not exceed 10 percent, when the average Hg concentration is greater than 1.0 µg/dscm. If the 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 D6784-02 (Reapproved 2008), “Standard Test

Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method)” (incorporated by reference, see §63.14) is used, the time per run must be long enough to collect a sufficient mass of Hg to analyze. Complete the RATA within 168 unit operating hours, except when Method 29 or ASTM D6784-02 is used, in which case up to 336 operating hours may be taken to finish the test.

4.1.1.5.2 *Calculation of RATA Results.* Calculate the relative accuracy (RA) of the monitoring system, on a µg/scm basis, as described in section 12 of Performance Specification (PS) 2 in appendix B to part 60 of this chapter (see Equations 2–3 through 2-6 of 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 µg/dscm, ≤10% of section 1 Hg mass;

4.1.2.2.2 For stack Hg concentrations ≤1 µg/dscm and >0.5 µg/dscm, ≤20% of section 1 Hg mass;

4.1.2.2.3 For stack Hg concentrations ≤0.5 µg/dscm and >0.1 µg/dscm, ≤50% of section 1 Hg mass; and

4.1.2.2.4 For stack Hg concentrations ≤0.1 µg/dscm, no breakthrough criterion assuming all other QA/QC specifications are met.

4.1.2.3 The type of sorbent material used by the traps during the RATA must be the same as for daily operation of the monitoring system; however, the size of the traps used for the RATA may be smaller than the traps used for daily operation of the system.

4.1.2.4 *Calculation of RATA Results.* Calculate the relative accuracy (RA) of the sorbent trap monitoring system, on a µg/scm basis, as described in section 12 of Performance Specification (PS) 2 in appendix B to part 60 of this chapter (see Equations 2-3 through 2-6 of PS2). For purposes of calculating the relative accuracy, ensure that the reference method and monitoring system data are on a consistent moisture basis, either wet or dry. The main and alternative RATA performance specifications in Table A-1 for Hg CEMS also apply to the sorbent trap monitoring system.

4.1.2.5 *Bias Adjustment.* Measurement or adjustment of sorbent trap monitoring system data for bias is not required.

4.1.3 *Diluent Gas, Flow Rate, and/or Moisture Monitoring Systems.* Monitoring systems that are used to measure stack gas volumetric flow rate, diluent gas concentration, or stack gas moisture content, either for routine operation of a sorbent trap monitoring system or to convert Hg concentration data to units of the applicable emission

limit, must be certified in accordance with the applicable provisions of part 75 of this chapter.

4.2 *Recertification.* Whenever the owner or operator makes a replacement, modification, or change to a certified CEMS or sorbent trap monitoring system that may significantly affect the ability of the system to accurately measure or record pollutant or diluent gas concentrations, stack gas flow rates, or stack gas moisture content, the owner or operator shall recertify the monitoring system. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit operation that may significantly change the concentration or flow profile, the owner or operator shall recertify the monitoring system. The same tests performed for the initial certification of the monitoring system shall be repeated for recertification, unless otherwise specified by the Administrator. Examples of changes that require recertification include: replacement of a gas analyzer; complete monitoring system replacement, and changing the location or orientation of the sampling probe.

## 5. ONGOING QUALITY ASSURANCE (QA) AND DATA VALIDATION

### 5.1 Hg CEMS.

5.1.1 *Required QA Tests.* Periodic QA testing of each Hg CEMS is required following initial certification. The required QA tests, the test frequencies, and the performance specifications that must be met are summarized in Table A-2, below. All tests must be performed with the affected unit(s) operating (*i.e.*, combusting fuel), however, the daily calibration may optionally be performed offline. 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 or $ 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 or $ R - A_{\text{avg}}  \leq 0.8 \mu\text{g}/\text{scm}$ .
Linearity check or 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 or $ R - A_{\text{avg}}  \leq 0.8 \mu\text{g}/\text{scm}$ .

TABLE A-2—ON-GOING QA TEST REQUIREMENTS FOR H<sub>g</sub> CEMS—Continued

Perform this type of QA test . . .	At this frequency . . .	With these qualifications and exceptions . . .	Acceptance criteria . . .
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>	≤20.0% RA or $ RM_{avg} - C_{avg}  +  CC  \leq 0.5 \mu\text{g}/\text{scm}$ , if $RM_{avg} < 2.5 \mu\text{g}/\text{scm}$ .

<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.



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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  $\text{lb}/\text{scf}$ . In cases where an appropriate F-factor is not listed in Table 19-2 of Method 19, you may use F-factors from Table 1 in section 3.3.5 of appendix F to part 75 of this chapter, or F-factors derived using the procedures in section 3.3.6 of appendix to part 75 of this chapter. Also, for startup and shutdown hours, you may calculate the Hg emission rate using the applicable diluent cap value specified in section 3.3.4.1 of appendix F to part 75 of this chapter, provided that the diluent gas monitor is not out-of-control and the hourly average  $\text{O}_2$  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  $E_{\text{Hj}}$  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:

$$M_h = K C_h Q_h$$

(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)

$$M_h = K C_h Q_h (1 - B_{ws})$$

(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 ( $\mu\text{g}/\text{scm}$ ).

$Q_h$  = 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 %  $\text{H}_2\text{O}/100$ )

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.

$$E_{ho} = \frac{M_h}{(MW)_h} \times 10^3$$

(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<sup>3</sup> = 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:

$\bar{E}_o$  = 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;

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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.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23408, Apr. 19, 2012; 78 FR 24093, Apr. 24, 2013; 79 FR 68795, Nov. 19, 2014; 81 FR 20203 Apr. 6, 2016; 82 FR 16740, Apr. 6, 2017; 85 FR 55766, Sept. 9, 2020]

### 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 ap-

pendix 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 accept-

ance 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  $E_{bo}$  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.

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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 knowl-

edge, 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 ongoing 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:

$C_{std}$  = PM concentration at standard conditions

$C_a$  = PM concentration at measurement conditions

$T_s$  = Stack Temperature (°F)

$T_{CEMS}$  = CEMS Measurement Temperature (°F)

$P_{CEMS}$  = CEMS Measurement Pressure (in. Hg)

$P_s$  = 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 emis-

sion 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:

$E_{heo}$  = Hourly gross output-based PM emission rate (lb/MWh)

$C_{std}$  = 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)

$B_{ws}$  = 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 num-

ber(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 ECMPS 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;

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- 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);



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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 ( $C_{gas}$ );

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  $O_2$ ;

28.14 Percent  $CO_2$ ;

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]

**Subpart VVVVV [Reserved]**