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40 CFR Parts 60 and 63
National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units; Technical Correction; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 60 and 63

[EPA–HQ–OAR–2009–0234 and EPA–HQ–OAR–2011–0044; FRL–9942–28–OAR]

RIN 2060–AS41

National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units; Technical Correction

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule; technical corrections.

SUMMARY: This action finalizes the technical corrections that the Environmental Protection Agency (EPA) proposed on February 17, 2015, to correct and clarify certain text of the EPA's regulations regarding ''National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units''. We are also taking final action to remove the rule provision establishing an affirmative defense for malfunction.

DATES: The effective date of this rule is April 6, 2016.

ADDRESSES: *Docket.* The EPA has established two dockets for this action: Docket ID No. EPA–HQ–OAR–2011–0044 (new source performance standards (NSPS) action) and Docket ID No. EPA–HQ–OAR–2009–0234 (Mercury and Air Toxics Standards (MATS) action). All documents in the dockets are listed in the *http://www.regulations.gov* index. Although listed in the index, some information is not publicly available (*e.g.,* confidential business information or other information whose disclosure is restricted by statute). Certain other material, such as copyrighted material, will be publicly available only in hard copy form. Publicly available docket materials are available either electronically in *http://www.regulations.gov* or in hard copy at the EPA Docket Center, Room 3334, EPA WJC West Building, 1301 Constitution Avenue NW., Washington, DC 20004. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: For questions about the MATS action: Mr. Jim Eddinger, Energy Strategies Group, Sector Policies and Programs Division (D243–01), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–5426; fax number (919) 541–5450; email address: *eddinger.jim@epa.gov.* For questions about the NSPS action: Mr. Christian Fellner, Energy Strategies Group, Sector Policies and Programs Division (D243–01), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–4003; fax number (919) 541–5450; email address: *fellner.christian@epa.gov.*

SUPPLEMENTARY INFORMATION:

A. How can I get copies of this document and other related information?

This **Federal Register** document and the document titled ''Summary of Public Comments and Responses: MATS and Utility NSPS Technical Corrections'' (TC RTC) are available in the dockets the EPA established under Docket ID No. EPA–HQ–OAR–2009–0234 and Docket ID No. EPA–HQ–OAR–2011–0044. The TC RTC is available in both the MATS and Utility NSPS dockets by conducting a search of the title ''Summary of Public Comments and Responses: MATS and Utility NSPS Technical Corrections.'' In addition to being available in the docket, electronic copies of these documents are available on the *www.regulations.gov* Web site. This **Federal Register** document and the TC RTC can also be found on the EPA's Technology Transfer Network (TTN) Web site at *http://www.epa.gov/ttn/atw/utility/utilitypg.html.*

B. Judicial Review

Under CAA section 307(b)(1), judicial review of this final rule is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit by June 6, 2016. Under CAA section 307(d)(7)(B), only an objection to this final rule that was raised with reasonable specificity during the period for public comment can be raised during judicial review. Note, under CAA section 307(b)(2), the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce these requirements.

I. Background

The final Clean Air Act (CAA) rules published in the **Federal Register** on February 16, 2012 (77 FR 9303), establish national emission standards for hazardous air pollutants (NESHAP) from coal- and oil-fired electric utility steam generating units (EGUs), referred to as ''MATS,'' and NSPS for fossil-fuel-fired electric utility, industrial-commercial-institutional, and small industrial-commercial-institutional steam generating units, referred to as the ''Utility NSPS''.

In the February 17, 2015, **Federal Register** (80 FR 8442), the EPA proposed to correct certain regulatory text. The proposed corrections were categorized generally as follows: (a) Resolution of conflicts between preamble and regulatory text, (b) corrections that were inadvertently not made that the EPA stated it would make in response to comments, and (c) clarification of language in regulatory text. In the proposed rule, the EPA identified each proposed technical correction to the regulatory text as found in the Code of Federal Regulations (*i.e.,* 40 CFR). Table 1 of this preamble lists the proposed revisions to the regulatory text that the EPA is finalizing. In Table 2 below, the EPA lists additional changes that the Agency determined were necessary to conform to changes the Agency included in the proposed rule.

TABLE 1—SUMMARY OF PROPOSED TECHNICAL CORRECTIONS AND CLARIFICATIONS BEING FINALIZED

Section of subpart Da (40 CFR part 60)	Description of correction (40 CFR part 60)
40 CFR 60.48Da(f)	Revise procedures for calculating compliance with the NSPS daily average particulate matter (PM) emission limit using PM continuous emission monitoring system (CEMS).
Section of subpart UUUUU (40 CFR part 63)	**Description of correction (40 CFR part 63)**
40 CFR 63.9983(a)	Revise to clarify that MATS does not apply to either major or area source combustion turbines, except for integrated gasification combined cycle (IGCC) units.
40 CFR 63.9983(b) and (c)	Revise consistent with the definitional changes in 40 CFR 63.10042.
40 CFR 63.9983(e)	Add to clarify applicability to units meeting the definition of a natural gas-fired EGU in MATS, and, because they combust greater than 10 percent biomass, also meet the definition of a biomass-fired boiler in the Industrial Boiler NESHAP (subpart DDDDD).
40 CFR 63.9991(c)(1) and (2)	Revise to clarify the conditions that are required in order to use the alternate sulfur dioxide (SO_2) limit.
40 CFR 63.10000(c)(1)(i)(A) and 63.10005(h)	Revise to clarify the provisions of units designated as being low emitting EGUs (LEE) when an acid gas scrubber and a bypass stack are present.
40 CFR 63.10000(c)(1)(i)(C)	Add to allow EGUs the ability to seek LEE status if their bypass stacks that are able to measure emissions and to allow EGUs with LEE status the ability to bypass emissions control devices during emergency periods.
40 CFR 63.10000(c)(2)(iii)	Revise to state that EGU choosing to use quarterly testing and parametric monitoring for hydrogen fluoride (HF) or hydrogen chloride (HCl) compliance must include the continuous monitoring systems (CMS) in their site-specific monitoring plans.
40 CFR 63.10000(m)	Add to clarify that EGUs choosing to meet the work practice standards contained in paragraph (2) of the definition of startup may verify, instead of certify, monitoring systems used to meet the work practice standards.
40 CFR 63.10001	Revise to remove the affirmative defense provisions.
40 CFR 63.10005(a)	Revise to clarify that different compliance demonstrations may require different and additional types of data collection and to clarify the date by which compliance must be demonstrated for existing EGUs.
40 CFR 63.10005(a)(2)	Revise to clarify the date by which compliance must be demonstrated for EGUs using CMS or sorbent trap monitoring systems.
40 CFR 63.10005(a)(2)(i)	Revise to clarify applicability of the provision to both the 30- and 90-boiler operating day performance testing requirements.
40 CFR 63.10005(b)(6)	Add to clarify the date EGUs must begin conducting required stack tests when stack test data collected prior to the applicable compliance date are submitted to satisfy initial performance test.
40 CFR 63.10005(d)(3) and (d)(4)(i)	Revise to more clearly state when compliance must be demonstrated.
40 CFR 63.10005(f)	Revise to clarify when sources must complete the initial tune-up after the compliance date, and the timing for subsequent tune-ups when the initial tune-up is conducted prior to the compliance date.
40 CFR 63.10005(h)(3)	Revise to clarify that the alternate 30- and 90-day averaging provisions are both applicable to mercury (Hg) emission limits.
40 CFR 63.10005(i)(4)	Revise to delete paragraphs (iii) and (iv). The identified test methods are not for determining fuel moisture content, as required in the provision.
40 CFR 63.10006(f)	Revise to specify EGU operational status with respect to performance testing; the requirements if the performance testing schedule is missed; and intervals between performance tests.
40 CFR 63.10009(a)(2) and (a)(2)(i)	Revise to clarify that the 90-boiler operating day averaging period is an option for Hg emissions from non-low rank virgin coal-fired EGUs.
40 CFR 63.10009(b)(1)	Revise to clarify group eligibility equations 1a and 1b.
40 CFR 63.10009(b)(2), (b)(3), (f)(2), (g)(1), (g)(2), and (j)(1)(ii).	Revise to correct the term ''gross electric output'' to ''gross output'' which is the term defined in 40 CFR 63.10042.
40 CFR 63.10009(f)	Revise to clarify the conditions for determining the ability of the emissions averaging group to meet the emissions limit and to clarify use of the alternate Hg emission limit.
40 CFR 63.10010(a)(4)	Revise to add requirement to route exhaust gases that bypass emissions control devices through stacks that contain monitoring so that emissions can be measured and to clarify that hours that a bypass stack is in use are to be counted as hours of deviation from monitoring requirements.
40 CFR 63.10010(f)(3)	Revise to clarify that 30-boiler operating day rolling averages are based only on valid hourly SO_2 emission rates.
40 CFR 63.10010(h)(6)(i) and (ii), (i)(5)(i)(A) and (B), and (j)(4)(i)(A) and (B).	Revise to clarify that data collected during certain periods are not to be included in compliance assessments but such periods are to be included in annual deviation reports.
40 CFR 63.10010(j)(l)(i)	Revise to replace the incorrect reference to § 63.7(e) with the correct reference to § 63.8(d)(2).
40 CFR 63.10010(l) and (l)(4)	Revise to clarify that EGU owners or operators who choose to meet the work practice standards contained in paragraph (2) of the definition of startup may verify, instead of certify, monitoring systems used.
40 CFR 63.10011(b)	Revise to remove the incorrect reference to Table 4 and to replace the incorrect reference to Table 7 with the correct reference to Table 6.

TABLE 1—SUMMARY OF PROPOSED TECHNICAL CORRECTIONS AND CLARIFICATIONS BEING FINALIZED—Continued

Section of subpart UUUUU (40 CFR part 63)	Description of correction (40 CFR part 63)
40 CFR 63.10011(c)(1) and (2)	Revise to clarify the date by which compliance must be demonstrated by EGUs that use CEMS or sorbent trap monitoring systems and to clarify in 40 CFR 63.10011(c)(1) that the alternate Hg emission limit may be used.
40 CFR 63.10011(e)	Revise to replace ''according to'' with ''in accordance with.''
40 CFR 63.10011(g)(4)(v)(A) and Table 3	Revise to clarify our intent by changing ''to the maximum extent possible'' to ''to the maximum extent possible, taking into account boiler or control device integrity.''
40 CFR 63.10020(e)	Revise to clarify that it applies only to EGU owners or operators who choose to meet the work practice standards contained in paragraph (2) of the definition of startup. In addition, the undefined term ''electrical load'' has been replaced with the defined term ''gross output'' and the incorrect terms ''liquid to fuel ratio'' and ''the differential pressure of the liquid'' have been replaced with the correct terms ''liquid to flue gas ratio'' and ''the pressure drop across the scrubber.''
40 CFR 63.10021(d)(3)	Revise to clarify the type of monitoring that is to be used to demonstrate compliance.
40 CFR 63.10021(e)	Revise to clarify the condition that allows delay of burner inspections for initial tune-ups.
40 CFR 63.10021(e)(9)	Revise to clarify the dates that tune-ups must be reported.
40 CFR 63.10023(b) and Table 6	Revise to clarify that all EGUs using PM continuous parametric monitoring systems (CPMS) for compliance purposes are to follow the same procedure for determining the operating limit.
40 CFR 63.10030(e)(1)	Revise to replace the phrase ''identification of which subcategory the source is in'' with ''identification of the subcategory of the source.''
40 CFR 63.10030(e)(7)(i)	Revise to delete and reserve since subsequent performance tests are not part of the Notification of Compliance Status.
40 CFR 63.10030(e)(7)(iii)	Add to establish the procedures by which an EGU owner or operator may switch between mass per heat input and mass per gross output emission limits.
40 CFR 63.10030(e)(8)(i)	Revise to clarify that it applies only to EGU owners or operators who choose to meet the work practice standards contained in paragraph (2) of the definition of startup. Revise to clarify that PM control device efficiencies and PM emission rates are those of periods other than startup and shutdown periods.
40 CFR 63.10030(e)(8)(ii)	Revise to remove the requirement for use of an independent professional engineer.
40 CFR 63.10030(f)	Revise to add notification requirements for EGUs that move in and out of MATS applicability.
40 CFR 63.10031(c)(4)	Revise to clarify the reporting requirements for EGU tune-ups.
40 CFR 63.10031(c)(5)	Revise to clarify that it applies only to EGU owners or operators who choose to meet the work practice standards contained in paragraph (2) of the definition of startup.
40 CFR 63.10031(c)(6)	Revise to add emergency bypass reporting for EGUs with LEE status.
40 CFR 63.10032(f)	Revise to clarify that the requirements of § 63.10032(f)(1) apply only to those EGU owners or operators who choose to meet the work practice standards contained in paragraph (1) of the definition of startup, while the requirements of § 63.10032(f)(2) apply only to those EGU owners or operators who choose to meet the work practice standards contained in paragraph (2) of the definition of startup.
40 CFR 63.10042	The definitions of ''Coal-fired electric utility steam generating unit,'' ''Coal refuse,'' ''Fossil fuel-fired,'' ''Integrated gasification combined cycle electric utility steam generating unit or IGCC,'' ''Limited-use liquid oil-fired subcategory,'' ''Natural gas-fired electric utility steam generating unit,'' and ''Oil-fired electric utility steam generating unit'' are revised to clarify the period of time to be included in determining the source's applicability to the MATS. A definition of ''neural network'' is added because the term is used in 40 CFR 63.10005(f), 63.10006(i), and 63.10021(e) and Table 3 to subpart UUUUU of Part 63 but is not defined.
Table 1 to subpart UUUUU of part 63	Revise to correct the term ''gross electric output'' to ''gross output'' which is the term defined in 40 CFR 63.10042.
Table 2 to subpart UUUUU of part 63	Revise to correct the term ''gross electric output'' to ''gross output'' which is the term defined in 40 CFR 63.10042. Provision 1(c) (the Hg limit for EGUs in the subcategory ''unit designed for coal ≥8,300 Btu/lb'') is also revised to clarify the applicability of the alternate 90-boiler operating day compliance option.
Table 3 to subpart UUUUU of part 63	Revise as described earlier to clarify the term ''maximum extent possible.''.
Table 4 to subpart UUUUU of part 63	Revise to clarify that existing as well as new EGUs using PM CPMS share the same procedures for developing operating limits.
Table 5 to subpart UUUUU of part 63	Revise to clarify that when using Method 29, the metals matrix spike and recovery levels are to be reported.
Table 6 to subpart UUUUU of part 63	Revise to clarify that existing, as well as new, EGUs using PM CPMS share the same procedures for developing operating limits.
Table 8 to subpart UUUUU of part 63	Revise to clarify that compliance reports are to include information required by 40 CFR 63.10031(c)(5) and (6).
Table 9 to subpart UUUUU of part 63	Revise to correct an inadvertent omission of 30-day notification requirements of 40 CFR 63.9.
Paragraphs 4.1.1.3 and 5.1.2.3 and Tables A–1 and A–2 to appendix A.	Revise to adjust Hg CEMS language regarding converters.
Paragraph 7.1.2.5 to appendix A	Add to require that owners or operators flag EGUs that are part of emission averaging groups.
Paragraph 3.2.1.2.1 of appendix A	Revise to specifically indicate that Hg gas generators and cylinders are allowed.
Paragraphs 4.1.1.1, Table A–1, Table A–2, 5.1.2.1, and 4.1.1.3 of appendix A.	Revise to exclude use of oxidized Hg gas standards for daily calibration of Hg CEMS.
Paragraph 5.1.2.3 of appendix A	Revise to make the weekly single level system integrity check mandatory.

TABLE 1—SUMMARY OF PROPOSED TECHNICAL CORRECTIONS AND CLARIFICATIONS BEING FINALIZED—Continued

Section of subpart UUUUU (40 CFR part 63)	Description of correction (40 CFR part 63)
Paragraphs 4.1.1.5.2, Table A–1, Table A–2, and 4.1.1.5 of appendix A.	Revise to provide an alternative relative accuracy test audit (RATA) procedure for EGUs with low emissions.
Paragraph 5.2.1 of appendix A	Revise to correct the number of days for sorbent trap use from 14 to 15.
Paragraph 6.2.2.3 of appendix A	Revise to clarify that the 90-day alternative Hg standard may be used and that electrical output is gross output.
Paragraph 7.1.2.6 of appendix A	Add to clarify that EGU owners or operators are to keep records of their EGUs that constitute emissions averaging groups.
Paragraphs 2.1, 2.3, 2.3.1, 2.3.2, 3.1, 3.2, 3.3, 5, 5.1, 5.2, and 5.3 of appendix B.	Revise to clarify that use of Performance Specification (PS) 18, when promulgated, will be allowed.
Paragraph 5.4 of appendix B	Add as part of the renumbering due to the addition of PS 18.
Paragraph 8 of appendix B	Revise to accommodate use of PS 18.
Paragraphs 10.1.8, 10.1.8.1, 10.1.8.1.1, and 10.1.8.1.2 of appendix B.	Revise as part of the renumbering due to the addition of PS 18.
Paragraph 10.1.8.1.3 of appendix B	Revise to clarify that records of relative accuracy audits (RAAs) are also required.
Paragraphs 10.1.8.2, 10.1.8.1.2.1, and 10.1.8.1.2.2 of appendix B.	Revise to clarify the quarterly gas audit recordkeeping requirements for PS 15 and the quarterly data accuracy assessments for PS 18 (which are reserved).
Paragraph 11.4 of appendix B	Revise to replace the incorrect abbreviation "*i.e.*" with "*e.g.*".
Paragraph 11.4.2 of appendix B	Revise to specify the requirements of the daily beam intensity checks for EGUs using PS 18.
Paragraph 11.4.3 of Appendix B	Revise to reflect the reporting requirements for PS 15.
Paragraph 11.4.4 of appendix B	Revise to reserve the reporting requirements for quarterly parameter verification checks for PS 18.
Paragraphs 11.4.4.1, 11.4.5, 11.4.5.1, 11.4.6, 11.4.6.1 of appendix B.	Add to reserve the reporting requirements for quarterly gas audit information and for quarterly dynamic spiking for PS 18.
Paragraph 11.4.7 of appendix B	Add to include reporting requirements for RAAs.
Paragraphs 11.4.7.1 through 11.4.7.13 of appendix B.	Add as part of the renumbering due to the addition of PS 18.
Paragraph 11.5.3.4 of appendix B	Revise to include reporting requirements for beam intensity checks for PS 18.

Most of the corrections and clarifications remain the same as presented in the proposed correction document and those changes are being finalized without further discussion. However, the EPA has made some changes in this final rule after consideration of the public comments received on the proposed correction document. The changes are to clarify applicability and implementation issues associated with proposed changes, and the significant changes are discussed below in this preamble. A summary of the comments received and our responses thereto is contained in the document ''Summary of Public Comments and Responses: MATS and Utility NSPS Technical Corrections'' located in the dockets for these rulemakings.

II. Significant Changes Since Proposal

This section of the preamble summarizes the significant changes made to the proposed corrections and clarifications.

1. Section 63.9984(f) is revised to add ''or the EGU's otherwise applicable compliance date established by the EPA or the state.'' A commenter stated that the EPA's proposed revision, which was adding ''the date that compliance must be demonstrated, as given'' in § 63.9984, to the initial compliance requirements in § 63.10005(a) for existing EGUs, does not effectively clarify the date that compliance must be demonstrated due to its reference to § 63.9984 and paragraph (f) of § 63.9984 because § 63.9984(b) specifies a compliance date of April 16, 2015 for existing EGUs. Also, § 63.9984(f), which states the dates by which compliance must be demonstrated, refers to § 63.9984(b). Therefore, we revised § 63.9984(f) because specifying a date for existing EGUs to demonstrate compliance is confusing for existing sources that have been granted a compliance extension.

2. Section 63.10000(n) is added to address comments that noted the proposed technical corrections did not address the permanent conversion to natural gas or biomass consistent with the proposals outlined in the February 17, 2015 preamble. In the preamble (see 80 FR 8447), we stated ''The EPA is also proposing that sources that permanently convert to natural gas or biomass after the compliance date are no longer subject to MATS, notwithstanding the coal or oil usage the previous 3 calendar years.'' However, we inadvertently did not include the necessary language to address permanent conversions in the proposed regulatory text. For that reason, we are revising paragraph (n) to incorporate the proposed change as outlined in the preamble to the proposed rule.

3. The proposal to revise § 63.10005(b)(1) to change the time period allowed for existing EGUs to use stack test data collected prior to the applicable compliance date has been withdrawn. Several commenters did not support the proposed revision to change the window in which initial compliance can be demonstrated, and said that EGUs should be allowed to demonstrate initial compliance using stack tests conducted on or after April 16, 2014. Commenters said the EPA's proposed change is unfair, renders investments in stack testing useless, and requires companies to perform new, unnecessary initial compliance testing. For these reasons, and because the Agency believes earlier stack tests may be representative under certain circumstances, the EPA is not making the proposed change.

4. Section 63.10006(f) is revised to: (1) Correct the minimum time between annual performance tests (from 370 to 320 calendar days); (2) clarify the minimum time between annual sorbent trap mercury testing for 30-boiler operating day low emitting EGU (LEE) retests (also 320 calendar days); and (3) provide the minimum time between annual sorbent trap mercury testing for 90-boiler operating day LEE retests (230 calendar days). Commenters correctly stated that the 370-day interval for annual tests was a typographical error, as they would expect the interval to be 365 days or less. Commenters expressed concerns that, while the proposed revised § 63.10006(f) specified the time

periods between annual performance tests, it did not specify the time periods between annual sorbent trap mercury testing for either the 30-boiler operating day averaging periods or the 90-boiler operating day averaging periods. The three revisions, listed above, being made to § 63.10006(f) address the commenters' concerns. In addition, § 63.10010(i)(2)(i) and (ii) is revised to clarify the time periods between quarterly, annual, and three year testing for particulate matter continuous emissions monitoring system (PM CEMS) audits.

5. Section 63.10009(b)(1) is revised to clarify group eligibility equations 1a and 1b. The purpose of the group eligibility equations is to provide EGU owners or operators a quick method for demonstrating initial compliance with the emission limits for all units participating in the emission averaging group using the maximum rated heat input or gross output of each unit and the results of the initial compliance demonstrations. Commenters stated that the EPA proposed to drop the double summation in the denominator, which is a correct step. However, the commenters indicated they do not understand what the Agency was thinking with respect to adding the ''q_j'' term in both the numerator and denominator and that the EPA defined ''q_j'' to be the hours in the averaging period (720 for 30-day averages and 2,160 for 90-day averages) because the term's presence in both the numerator and denominator cancels out and has no effect. Commenters also stated that they do not agree that the newly proposed group averaging eligibility Equation 1a is more useful than the original equation. Commenters said both the original equation and the newly proposed equation are flawed and, thus, produce incorrect results. Commenters said corrections need to be made to either equation that the EPA wants to use. Commenters said the stack testing components of the equation for each unit that is tested need to be weighted the same as units that use continuous monitoring in order for any equation to produce correct calculations. Commenters said the original equation works for the continuous monitoring components, but is flawed because it does not properly weight the stack testing components, and the newly proposed equation is flawed on both fronts. Based on the commenters' concerns, the equations have been revised so that individual EGU characteristics, whether from continuous emission monitoring systems (CEMS) or stack testing results, are easier to input. We agree that the added ''q_j'' term and ''r_k'' term have no effect, and they have been deleted. We are also deleting the ''n'' term since Equations 1a and 1b are to demonstrate initial compliance based on using the initial compliance results and not continuous compliance that is based on an averaging period. We have revised some of the terms' descriptions to clarify that the emission rates used are those determined during the initial compliance demonstration.

6. Section 63.10009(e), (g), and (j)(2) are revised to require compliance with the weighted average emissions rate at all times following the date that emissions averaging begins. A commenter argued that the EPA must also revise these sections to remove the specifically identified dates (*e.g.,* April 16, 2015 and February 16, 2015). We agree that the dates within § 63.10009(e), (g), and (j)(2) should be removed, and the dates have been replaced with ''the date that you begin emission averaging.''

7. Section 63.10010(h)(6)(i), (i)(5)(i)(A), and (j)(4)(i)(A) and (B) are revised to clarify when monitoring system quality assurance or quality control activities are to be reported. Commenters said § 63.10010(h)(6)(i), (i)(5)(i)(A), and (j)(4)(i)(A) and (B) specify what data from particulate matter (PM) continuous parameter monitoring system (CPMS), PM CEMS, and hazardous air pollutants (HAP) metal CEMS must be excluded from compliance determinations and that the EPA proposed to separate the language regarding deviation reporting that currently appears at the end of these provisions into a separate sentence to ''ease readability.'' The commenter disagreed that the proposed revision improves readability and said that, to the contrary, by separating out the sentence, the EPA implies that the periods when data are not collected because of monitoring system malfunctions, repairs, required quality assurance or quality control, as well as periods when a monitoring system is out of control, are deviations from monitoring requirements, which they are not. The commenter is incorrectly interpreting the proposed change. Periods when data are not collected because of monitoring system malfunctions are deviations. The required quality assurance or quality control activities that are deviations from monitoring requirements are, as stated in § 63.10010(h)(6)(i), (i)(5)(i)(A), and (j)(4)(i)(A) and (B), those conducted during monitoring systems malfunctions.

8. Section 63.10011(g)(4)(v)(A) is revised to change the proposed language ''to the maximum extent practicable'' back to the language ''to the maximum extent possible'' as in the final rule. Commenters said the requirement to use clean fuels ''to the maximum extent practicable'' does not even address the level of toxic emissions during startup, let alone reduce them to the maximum extent achievable as is required under CAA section 112(d)(2). Commenters said, perhaps most importantly, that the EPA's proposed change impermissibly assumes that existing older boilers and control devices are not capable of being upgraded—despite Congress' mandate in CAA section 112(d)(2)–(3) that emissions standards and work practices reflect what is achievable and actually being achieved by the best-performing sources. Commenters said further, under CAA section 112(d), it is the Administrator's duty to establish standards to achieve the required emissions reductions—not the duty of owners and operators. Commenters said the EPA's purported work practices impermissibly allow operators themselves to determine the standards and their own emission reductions achieved (or not) by the requirements. Commenters said the EPA's proposed change leaves it up to each operator to determine the amount of clean fuel use that represents the ''maximum extent practicable,'' and leaves it up to each operator to determine what qualifies as a ''consideration such as boiler or control device integrity.'' Commenters said that even though the requirement for clean fuels states that EGUs must have sufficient clean fuel capacity to engage and operate PM control devices within 1 hour of adding the primary fuel (and even though a separate work practice requires PM controls to be engaged and operated within 1 hour), these requirements do not establish whether and to what point EGUs must actually use clean fuels in startups. These comments primarily concern issues that the EPA did not reopen in the proposed document. Because those issues were not reopened, the EPA did not respond to these comments. We did propose to change § 63.10011(g)(4)(v)(A) as the commenter states. We continue to believe that the use of clean fuels during startup must be maximized to reduce HAP emissions and have reconsidered the proposed change of ''possible'' to ''practicable.'' We believe ''possible'' is a more enforceable standard. The final change to § 63.10011(g)(4)(v)(A) is: ''to the maximum extent possible, taking into account considerations such as boiler or control device integrity,

throughout the startup period.'' This language is also included in section 4 of Table 3, to clarify that this provision applies during periods of shutdown.

The EPA is not finalizing the proposed change because we have determined that requiring clean fuel use to the maximum extent ''possible'' is more enforceable than the proposed change to ''practicable'', and the Agency believes it is critical that the work practice be enforceable to ensure that sources use as much clean fuel with its inherently low HAP content as possible when a source's controls are not yet fully engaged. At the same time, we believe operators must be able to consider the integrity of the EGU system when determining the clean fuel use that is ''possible'' for a given unit. We believe the final rule addresses both considerations.

9. Section 63.10030(e)(8)(iii) is added to allow EGU owners or operators the ability to switch between paragraphs 1 and 2 of the startup definition. Commenters requested that switching between paragraphs of the definition of startup not be prohibited. We have no objection to such switching provided certain criteria are met. Just as we had not considered that EGU owners or operators would want to switch between mass per year heat input emission limits and mass per gross output emission limits, but proposed to allow such changes provided certain criteria are met, we did not consider that an owner or operator would want to switch between the startup definitions for the EGU. Given the commenter's specific request and the EPA's conditional approval based on the already existing model given in § 63.10030(e)(7)(iii)(A), § 63.10030(e)(8)(iii) is added to the rule. This new section allows EGU owners or operators the ability to switch between paragraphs 1 and 2 of the startup definition provided, among other things, that the EGUs involved in the switch are identified, that a request is submitted 30 days prior to the anticipated switch, that the request contains certification that all previous plans, such as monitoring and emissions averaging, are revised, that records are maintained, and that the new definition is not used until the next reporting period after receipt of written acknowledgement from the Administrator or the delegated authority of the switch.

10. Section 63.10031(c)(4) is revised to clarify that the ''date'' of the tune-up is the date the tune-up provisions specified in § 63.10021(e)(6) and (7) are completed. Commenters noted that there will not necessarily be a single date associated with completion of an EGU's tune-ups conducted under § 63.10021(e) and suggested that, related to the possibility of a delayed burner inspection, the Agency make it clear that compliance with all requirements besides the burner inspection must occur by the compliance demonstration date, but that the burner inspection may be delayed, and to revise the provision to recognize that as a result, performance of subsequent inspections and tune-ups may be on a separate 36-month track and some EGUs may have ''dates'' rather than a ''date'' for completion of requirements. Regardless of when the burner inspection is conducted, the tune-up is considered to have been conducted on the date the combustion optimization is completed. The purpose of the tune-up is the optimization of the combustion to minimize organic HAP, carbon monoxide, and nitrogen oxides (NO_X) and to improve or return the unit to its design combustion efficiency (*i.e.,* § 63.10021(e)(6) and (7)). We realize that EGUs may need to be taken off-line to conduct an inspection of burners. So, we allow that inspection to be delayed, or as § 63.10021(e) is revised, to be performed prior to the tune-up. Therefore, subsequent tune-ups must be performed within 36 months from when the previous tune-up (*i.e.,* the requirements of § 63.10021(e)(6) and (7)) was completed, and the source must conduct the next burner inspection on a similar schedule.

11. Section 63.10031(c)(7) is added to include the reporting requirements that have been removed from § 63.10030(e)(7)(i). A commenter said that there is no reason to submit Notification of Compliance Status (NOCS) for ongoing 3-year tests that are performed to demonstrate that LEE status is maintained, so the proposed language in § 63.10030(e)(7)(i) should be revised. We agree that not only the ongoing 3-year LEE retests, but also the annual and quarterly LEE retests and annual retests that are performed to establish operating limits, should not be submitted as NOCS. According to the introductory text of § 63.10030(e), the NOCS is required only for reporting initial compliance. Therefore, § 63.10030(e)(7)(i) has been removed and reserved, and the reporting requirements in § 63.10030(e)(7)(i) have been moved to a new place, *i.e.,* § 63.10031(c)(7), and are part of the compliance report requirements. Likewise, the compliance certification and deviation information requirements in § 63.10030(e)(5) and (e)(6) apply for compliance reports and are replicated in new § 63.10031(c)(8) and (9), and each of these paragraphs is included in the introductory text in § 63.10030(c) and in Table 8.

12. The definitions of ''Coal-fired electric utility steam generating unit,'' ''Fossil fuel-fired,'' ''Limited-use liquid oil-fired subcategory,'' and ''Oil-fired electric utility steam generating unit'' in § 63.10042 are further revised to clarify the period of time to be included in determining the source's applicability to the MATS.

One commenter indicated that the proposed rule does not address permanent conversion to natural gas or biomass, nor does it make clear that, after the first 3 years of compliance, EGUs are required to evaluate applicability based on coal or oil usage from the 3 previous calendars years on an annual rolling basis. The commenter said that the EPA's clarifying proposals are not clearly outlined in the proposed revised definitions. The commenter urged the EPA to revise the definition in a manner consistent with the proposals outlined in the preamble. Several commenters indicated the proposed changes do not prevent an EGU from continuing to be subject to MATS for several years after a fuel switch.

We agree that the proposed clarification to the definitions does not make it clear that, after the first 3 years of compliance, an EGU is required to evaluate applicability based on coal or oil usage from the 3 previous calendar years on an annual rolling basis. Thus, we have revised the definitions for ''Coal-fired electric utility steam generating unit,'' ''Oil-fired electric utility steam generating unit,'' and ''Fossil fuel-fired'' to clarify that applicability after the first 3 years of compliance will be based on coal or oil usage from the 3 previous calendar years on an annual rolling basis.

Concerning the permanent fuels switch, the EPA explained above that it has addressed permanent conversions in § 63.10000(n) of the final rule, as discussed in paragraph 2 above.

13. Appendix A is finalized with all proposed revisions with the exception of adding an alternative specification for the relative accuracy test audit (RATA) where commenters provided data to support a different approach using an absolute value criterion. However, due to the current lack of available NIST-traceable elemental Hg gas cylinders, owners or operators of EGUs that have purchased/installed Hg CEMS that lack integrated elemental Hg gas generators may continue to use NIST-traceable oxidized gases for calibration error tests and daily checks until such time that NIST-traceable compressed elemental Hg gas standards are available and traceable with a combined uncertainty

(K=2) of 5 percent. Once those standards are available, we will issue a notice of availability in the **Federal Register**. Should NIST-traceable oxidized mercury reference gases with a combined uncertainty of 5% ultimately be available, we will consider allowing their use for calibration error tests and checks.

14. Appendix B is finalized with all proposed revisions except those related to sections 10 and 11 regarding recordkeeping and reporting for hydrogen chloride (HCl) CEMS subject to PS 18. Sections 10 and 11 will be addressed in the upcoming MATS Completion of Electronic Reporting Requirements rule. One change has been made that was not proposed. A minor technical correction has been made to section 9.4, requiring the HCl emission rates to be reported to 2 significant figures in scientific notation, which is consistent with the way that the emission standards are presented in Tables 1 and 2.

III. Other Corrections and Clarifications

In finalizing the rule, the EPA is addressing several other technical corrections and clarifications in the regulatory language based on public comments that were received on the February 2015 proposal that the Agency determined were necessary to conform to changes included in the proposed rule, as outlined in Table 2 of this preamble.

TABLE 2—SUMMARY OF TECHNICAL CORRECTIONS AND CLARIFICATIONS SINCE FEBRUARY 17, 2015, PROPOSAL

Section of subpart UUUUU (40 CFR part 63)	Description of correction (40 CFR part 63)
40 CFR 63.10000(a)	Revise this paragraph by adding "items 3 and 4" to clarify which items in Table 3 must be met.
40 CFR 63.10000(f)	Revise this paragraph to add "Except as provided under paragraph (n) of this section" due to the addition of paragraph (n) clarifying the applicability of a permanent conversion to natural gas or biomass.
40 CFR 63.10000(g)	Revise this paragraph to add "Except as provided under paragraph (n) of this section" due to the addition of paragraph (n) clarifying the applicability of a permanent conversion to natural gas or biomass.
40 CFR 63.10000(i)(1)	Revise this paragraph to clarify that an EGU, no longer subject to MATS, must be in compliance with applicable CAA section 112 or 129 standards consistent with paragraphs (g) and (n).
40 CFR 63.10005(a)	Revise this paragraph to replace the terms "electrical" and "electrical load" with the terms "gross" and "gross output," respectively, to be consistent with the proposed changes to other sections.
40 CFR 63.10005(a)(2)(ii)	Revise this paragraph to replace the terms "electrical" and "electrical load" with the terms "gross" and "gross output," respectively, to be consistent with the proposed changes to other sections.
40 CFR 63.10005(b)(4)	Revise this paragraph to replace the term "electrical load" with the term "gross output" to be consistent with the proposed changes to other sections.
40 CFR 63.10005(f)	Revise to be consistent with EPA's intent, as explained in the preamble to the proposed rule, to only clarify the timing of initial and subsequent tune-ups. Revise since specifying the date is problematic for sources that have been granted a compliance extension.
40 CFR 63.10005(h)(3)(i)(D)	Revise this paragraph to replace the term "electrical load" with the term "gross output" to be consistent with the proposed changes to other sections.
40 CFR 63.10005(h)(3)(iii)	Revise this paragraph to replace the term "electrical load" with the term "gross output" to be consistent with the proposed changes to other sections.
40 CFR 63.10007(f)(2)	Revise this paragraph to replace the term "electrical load" with the term "gross output" to be consistent with the proposed changes to other sections.
40 CFR 63.10009(e) and (j)(2)	Revise since specifying the date is problematic for sources that have been granted a compliance extension.
40 CFR 63.10010(f)(4)	Revise this paragraph to replace the term "electrical load" with the term "gross output" to be consistent with the proposed changes to other sections.
40 CFR 63.10021(h)(1)	Revise this paragraph to replace the term "electrical load" with the term "gross output" to be consistent with the proposed changes to other sections.
Table 5	Revise this table to replace the term "electrical" with the term "gross" to be consistent with the proposed changes to other sections.
Paragraph 7.1.8.5 of appendix A	Revise this paragraph to replace the term "electrical load" with the term "gross output" to be consistent with the proposed changes to other sections.

IV. Affirmative Defense for Violation of Emission Standards During Malfunction

The EPA received numerous comments on the affirmative defense to civil penalties for violations caused by malfunctions that the EPA proposed to remove in the current rule. Several commenters supported the removal of the affirmative defense for malfunctions. Other commenters opposed the removal of the affirmative defense provision.

As stated in the February 17, 2015, proposal, the United States Court of Appeals for the District of Columbia Circuit vacated an affirmative defense in one of the EPA's CAA section 112(d) regulations. *NRDC* v. *EPA,* No. 10–1371 (D.C. Cir. April 18, 2014) 2014 U.S. App. LEXIS 7281 (vacating affirmative defense provisions in CAA section 112(d) rule establishing emission standards for Portland cement kilns). The court found that the EPA lacked authority to establish an affirmative defense for private civil suits and held that under the CAA, the authority to determine civil penalty amounts in such cases lies exclusively with the courts, not the EPA. Specifically, the court found: "As the language of the statute makes clear, the courts determine, on a case-by-case basis, whether civil penalties are 'appropriate.' " See *NRDC,* 2014 U.S. App. LEXIS 7281 at *21 ("[U]nder this statute, deciding whether penalties are 'appropriate' in a given private civil suit is a job for the courts, not EPA.''). The EPA is finalizing the proposed removal of the regulatory affirmative defense provision from MATS. In the event that a source fails to comply with an applicable CAA section 112(d) standard as a result of a malfunction event, the EPA's ability to exercise its case-by-case-enforcement discretion to determine an appropriate response provides sufficient flexibility in such circumstances as was explained in the preamble to the proposed rule. Further, as the D.C. Circuit recognized, in an EPA or citizen enforcement action, the court has the discretion to consider any defense raised and determine whether penalties are appropriate. Cf. NRDC, 2014 U.S. App. LEXIS 7281 at *24 (arguments that violation were caused by unavoidable technology failure can be made to the courts in future civil cases when the issue arises). The same is true for the presiding officer in EPA administrative enforcement actions. For all these reasons, this final rule removes the affirmative defense provisions.

V. Impacts of This Final Rule

This action finalizes certain provisions and makes technical and clarifying corrections, but does not promulgate substantive changes to the February 2012 final MATS (77 FR 9304). Therefore, there are no environmental, energy, or economic impacts associated with this final action. The impacts associated with MATS are discussed in detail in the February 16, 2012, final MATS rule.

VI. Statutory and Executive Order Reviews

Additional information about these statutes and Executive Orders can be found at *http://www2.epa.gov/laws-regulations/laws-and-executive-orders.*

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

This action is not a significant regulatory action and was, therefore, not submitted to the Office of Management and Budget (OMB) for review.

B. Paperwork Reduction Act (PRA)

This action does not impose any new information collection burden under the PRA. OMB has previously approved the information collection activities contained in the existing regulations (40 CFR part 63, subpart UUUUU) and has assigned OMB control number 2060–0567. This action is believed to result in no changes to the ICR of the February 2012 final MATS rule, so that the information collection estimate of project cost and hour burden from the final MATS have not been revised.

C. Regulatory Flexibility Act (RFA)

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA. This action will not impose any requirements on small entities. This action finalizes changes to MATS to correct and clarify implementation issues raised by stakeholders.

D. Unfunded Mandates Reform Act (UMRA)

This action does not contain an unfunded mandate as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. This rule promulgates amendments to the February 2012 final MATS, but the amendments are clarifications to existing rule language to aid in implementation. Therefore, the action imposes no enforceable duty on any state, local, or tribal governments or the private sector.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government.

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

This action does not have tribal implications, as specified in Executive Order 13175. It will not have substantial direct effects on tribal governments, on the relationship between the federal government and Indian tribes, or on the distribution of power and responsibilities between the federal government and Indian tribes, as specified in Executive Order 13175. This action clarifies certain components of the February 2012 final MATS. Thus, Executive Order 13175 does not apply to this action.

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

The EPA interprets Executive Order 13045 as applying only to those regulatory actions that concern environmental health or safety risks that the EPA has reason to believe may disproportionately affect children, per the definition of ''covered regulatory action'' in section 2–202 of the Executive Order. This action is not subject to Executive Order 13045 because it does not concern an environmental health risk or safety risk.

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

This action is not subject to Executive Order 13211 because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act (NTTAA)

This action does not involve technical standards from those contained in the February 16, 2012, final rule. Therefore, the EPA did not consider the use of any voluntary consensus standards. *See* 77 FR 9441–9443 for the NTTAA discussion in the February 16, 2012, final rule.

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

The EPA believes the human health or environmental risk addressed by this action will **not** have potential disproportionately high and adverse human health or environmental effects on minority, low-income, or indigenous populations because it does not affect the level of protection provided to human health or the environment.

The environmental justice finding in the February 2012 final MATS remains relevant in this action, which finalizes changes to the rule to correct and clarify implementation issues raised by stakeholders.

K. Congressional Review Act (CRA)

This action is subject to the CRA, and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2).

List of Subjects

40 CFR Part 60

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

40 CFR Part 63

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

Dated: March 17, 2016.

Gina McCarthy,

Administrator.

For the reasons discussed in the preamble, the EPA amends 40 CFR parts 60 and 63 as follows:

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

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

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

■ 2. Section 60.48Da is amended by revising paragraph (f) to read as follows:

§ 60.48Da Compliance provisions.

* * * * *

(f) For affected facilities for which construction, modification, or reconstruction commenced before May 4, 2011, compliance with the applicable daily average PM emissions limit is determined by calculating the arithmetic average of all hourly emission rates each boiler operating day, except for data obtained during startup, shutdown, or malfunction periods. Daily averages are only calculated for boiler operating days that have non-out-of-control data for at least 18 hours of unit operation during which the standard applies. Instead, all of the non-out-of-control hourly emission rates of the operating day(s) not meeting the minimum 18 hours non-out-of-control data daily average requirement are averaged with all of the non-out-of-control hourly emission rates of the next boiler operating day with 18 hours or more of non-out-of-control PM CEMS data to determine compliance. For affected facilities for which construction or reconstruction commenced after May 3, 2011 that elect to demonstrate compliance using PM CEMS, compliance with the applicable PM emissions limit in § 60.42Da is determined on a 30-boiler operating day rolling average basis by calculating the arithmetic average of all hourly PM emission rates for the 30 successive boiler operating days, except for data obtained during periods of startup and shutdown.

* * * * *

PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

■ 3. The authority citation for part 63 continues to read as follows:

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

■ 4. Section 63.9983 is amended by:

■ a. Revising the section heading and paragraphs (a), (b), and (c); and

■ b. Adding paragraph (e).

The revisions and addition read as follows:

§ 63.9983 Are any fossil fuel-fired electric generating units 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).

* * * * *

(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.

■ 5. Section 63.9991 is amended by revising paragraphs (c)(1) and (2) to read as follows:

§ 63.9991 What emission limitations, work practice standards, and operating limits must I meet?

* * * * *

(c) * * *

(1) Has a system using wet or dry flue gas desulfurization technology and an SO_2 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_2 CEMS installed on the EGU consistent with § 63.10000(b).

■ 6. Section 63.10000 is amended by revising paragraphs (a), (c)(1)(i), (c)(2)(iii), (f), (g), and (i)(1) and adding paragraphs (m) and (n) to read as follows:

§ 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.

* * * * *

(c)(1) * * *

(i) For a coal-fired or solid oil-derived fuel-fired EGU or IGCC EGU, you may conduct initial performance testing in accordance with § 63.10005(h), to determine whether the EGU qualifies as a low emitting EGU (LEE) for one or more applicable emission limits, except as otherwise provided in paragraphs (c)(1)(i)(A) and (B) of this section:

(A) Except as provided in paragraph (c)(1)(i)(C) of this section, you may not pursue the LEE option if your coal-fired, IGCC, or solid oil-derived fuel-fired EGU is equipped with a main stack and a bypass stack or bypass duct configuration that allows the effluent to bypass any pollutant control device.

(B) You may not pursue the LEE option for Hg if your coal-fired, solid oil-derived fuel-fired EGU or IGCC EGU is new.

(C) You may pursue the LEE option provided that:

(*1*) Your EGU's control device bypass emissions are measured in the bypass stack or duct or your control device bypass exhaust is routed through the EGU main stack so that emissions are measured during the bypass event; or

(*2*) Except for hours during which only clean fuel is combusted, you bypass your EGU control device only during emergency periods for no more than a total of 2 percent of your EGU's annual operating hours; you use clean fuels to the maximum extent possible during an emergency period; and you prepare and submit a report describing the emergency event, its cause, corrective action taken, and estimates of emissions released during the emergency event. You must include these emergency emissions along with performance test results in assessing whether your EGU maintains LEE status.

* * * * *

(2) * * *

(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.

* * * * *

(f) Except as provided under paragraph (n) of this section, you are subject to the requirements of this subpart for at least 6 months following the last date you met the definition of an EGU subject to this subpart (*e.g.,* 6 months after a cogeneration unit provided more than one third of its potential electrical output capacity and more than 25 megawatts electrical output to any power distributions system for sale). You may opt to remain subject to the provisions of this subpart beyond 6 months after the last date you met the definition of an EGU subject to this subpart, unless your unit is a solid waste incineration unit subject to standards under CAA section 129 (*e.g.,* 40 CFR part 60, subpart CCCC (New Source Performance Standards (NSPS) for Commercial and Industrial Solid Waste Incineration Units, or subpart DDDD (Emissions Guidelines (EG) for Existing Commercial and Industrial Solid Waste Incineration Units). Notwithstanding the provisions of this subpart, an EGU that starts combusting solid waste is immediately subject to standards under CAA section 129 and the EGU remains subject to those standards until the EGU no longer meets the definition of a solid waste incineration unit consistent with the provisions of the applicable CAA section 129 standards.

(g) Except as provided under paragraph (n) of this section, if your unit no longer meets the definition of an EGU subject to this subpart you must be in compliance with any newly applicable standards on the date you are no longer subject to this subpart. The date you are no longer subject to this subpart is a date selected by you, that must be at least 6 months from the date that your unit last met the definition of an EGU subject to this subpart or the date you begin combusting solid waste, consistent with § 63.9983(d). Your source must remain in compliance with this subpart until the date you select to cease complying with this subpart or the date you begin combusting solid waste, whichever is earlier.

* * * * *

(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.

* * * * *

(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.

§ 63.10001 [Removed and Reserved]

■ 7. Section 63.10001 is removed and reserved.

■ 8. Section 63.10005 is amended by:

■ a. Revising paragraphs (a) introductory text, (a)(2) introductory text, (a)(2)(i) and (ii), and (b)(4);

■ b. Adding paragraph (b)(6);

■ c. Revising paragraphs (d)(3), (d)(4)(i), (f), (h) introductory text, (h)(3) introductory text, (h)(3)(i)(D), and (h)(3)(iii) introductory text; and

■ d. Removing paragraphs (i)(4)(iii) and (iv).

The revisions and additions read as follows:

§ 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.

* * * * *

(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_2 or PM CEMS, the initial performance test shall consist of 30- or, for certain coal-fired existing EGUs that use emissions averaging 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_2 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_2, O_2, or moisture, as applicable) during the performance test period, in order to convert the pollutant concentrations to units of the standard. If you choose to comply with a gross output-based emission limit, you must also collect hourly gross output data during the performance test period.

* * * * *

(b) * * *

(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

* * * * *

(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.

* * * * *

(d) * * *

(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) * * *

(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.

* * * * *

(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.

* * * * *

(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).

* * * * *

(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) * * *

(D) Hourly gross output data (megawatts), from facility records.

* * * * *

(iii) Calculate the average Hg concentration, in µg/m³ (dry basis), for the 30- (or 90-) boiler operating day performance test, as the arithmetic average of all Method 30B sorbent trap results. Also calculate, as applicable, the average values of CO_2 or O_2 concentration, stack gas flow rate, stack gas moisture content, and gross output for the test period. Then:

* * * * *

■ 9. Section 63.10006 is amended by revising paragraph (f) and removing paragraph (j) to read as follows:

§ 63.10006 When must I conduct subsequent performance tests or tune-ups?

* * * * *

(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.

* * * * *

■ 10. Section 63.10007 is amended by revising paragraph (f)(2) to read as follows:

§ 63.10007 What methods and other procedures must I use for the performance tests?

* * * * *

(f) * * *

(2) *Default gross output.* If you use CEMS to continuously monitor Hg, HCl, HF, SO_2, 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.

* * * * *

■ 11. Section 63.10009 is amended by revising paragraphs (a)(2) introductory text, (a)(2)(i), (b)(1) through (3), (e), (f) introductory text, (f)(2), (g), (j)(1)(ii), and (j)(2) introductory text to read as follows:

§ 63.10009 May I use emissions averaging to comply with this subpart?

(a) * * *

(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'' subcategory, the averaging time for emissions averaging for pollutants is 30 days (rolling daily) using data from CEMS or a combination of data from CEMS and manual performance (LEE) testing. 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-boiler operating days (rolling daily) using data from CEMS, sorbent trap monitoring, or a combination of monitoring data and data from manual performance (LEE) testing. 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) days during the preceding 30 (or 90) group boiler 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).

* * * * *

(b) * * *

(1) *Group eligibility equations.*

$$WAER_m = \frac{\left[\sum_{j=1}^{p} Herm_j \times Rmm_j\right] + \sum_{k=1}^{m} Ter_k \times Rmt_k}{\left(\sum_{j=1}^{p} Rmm_j\right) + \sum_{k=1}^{m} Rmt_k} \qquad (Eq. 1a)$$

Where:

$WAER_m$ = Maximum Weighted Average Emission Rate in terms of lb/heat input or lb/gross output,

$Herm_{i,j}$ = hourly emission rate (*e.g.,* lb/MMBtu, lb/MWh) from CEMS or sorbent trap monitoring as determined during the initial compliance determination from EGU j,

Rmm_j = Maximum rated heat input, MMBtu/h, or maximum rated gross output, MWh/h, for EGU j,

p = number of EGUs in emissions averaging group that rely on CEMS,

Ter_k = Emissions rate (lb/MMBTU or lb/MWh) as determined during the initial compliance determination of EGU k,

Rmt_k = Maximum rated heat input, MMBtu/h, or maximum rated gross output, MWh/h, for EGU k, and

m = number of EGUs in emissions averaging group that rely on emissions testing.

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

Where:

Variables with the similar names share the descriptions for Equation 1a of this section,

Smm_j = maximum steam generation, lb_{steam}/h or lb/gross output, for EGU j,

Cfm_j = 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_{steam} or MWh/lb_{steam}) from EGU j,

Smt_k = maximum steam generation, lb_{steam}/h or lb/gross output, for EGU k, and

Cfm_k = 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_{steam} or MWh/lb_{steam}) from EGU k.

(2) Weighted 30-boiler operating day rolling average emissions rate equations for pollutants other than Hg. 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_i = hourly emission rate (*e.g.,* lb/MMBtu, lb/MWh) from unit i's CEMS for the preceding 30-group boiler operating days,

Rm_i = hourly heat input or gross 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_i = Emissions rate from most recent emissions test of unit i in terms of lb/heat input or lb/gross output,

Rt_i = Total heat input or gross output of unit i for the preceding 30-boiler operating days, and

m = number of EGUs in emissions averaging group that rely on emissions testing.

$$WAER = \frac{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Her_i \times Sm_i \times Cfm_i)\right]_p + \sum_{i=1}^{m}(Ter_i \times St_i \times Cft_i)}{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Sm_i \times Cfm_i)\right]_p + \sum_{i=1}^{m}St_i \times Cft_i} \quad (Eq. 2b)$$

Where:

variables with similar names share the descriptions for Equation 2a of this section,

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

Cfm_i = conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit i that uses CEMS from the preceding 30 group boiler operating days,

St_i = steam generation in units of pounds from unit i that uses emissions testing, and

Cft_i = conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit i that uses emissions testing.

(3) Weighted 90-boiler operating day rolling average emissions rate equations for Hg emissions from EGUs in the ''coal-fired unit not low rank virgin coal'' subcategory. Use Equation 3a or 3b of this section to calculate the 90-day rolling average emissions daily.

$$WAER = \frac{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Her_i \times Rm_i)\right]_p + \sum_{i=1}^{m}(Ter_i \times Rt_i)}{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Rm_i)\right]_p + \sum_{i=1}^{m}Rt_i} \quad (Eq. 3a)$$

Where:

Her_i = hourly emission rate from unit i's CEMS or Hg sorbent trap monitoring system for the preceding 90-group boiler operating days,

Rm_i = hourly heat input or gross output from unit i for the preceding 90-group boiler operating days,

p = number of EGUs in emissions averaging group that rely on CEMS,

n = number of hours that hourly rates are collected over the 90-group boiler operating days,

Ter_i = Emissions rate from most recent emissions test of unit i in terms of lb/heat input or lb/gross output,

Rt_i = Total heat input or gross output of unit i for the preceding 90-boiler operating days, and

m = number of EGUs in emissions averaging group that rely on emissions testing.

$$WAER = \frac{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Her_i \times Sm_i \times Cfm_i)\right]_p + \sum_{i=1}^{m}(Ter_i \times St_i \times Cft_i)}{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Sm_i \times Cfm_i)\right]_p + \sum_{i=1}^{m}St_i \times Cft_i} \quad (Eq. 3b)$$

Where:

variables with similar names share the descriptions for Equation 2a of this section,

Sm_i = steam generation in units of pounds from unit i that uses CEMS or a Hg sorbent trap monitoring for the preceding 90-group boiler operating days,

Cfm_i = conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit i that uses CEMS or sorbent trap monitoring from the preceding 90-group boiler operating days,

St_i = steam generation in units of pounds from unit i that uses emissions testing, and

Cft_i = conversion factor, calculated from the most recent emissions test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit i that uses emissions testing.

* * * * *

(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.

* * * * *

(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_2, 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.

* * * * *

(j) * * *

(1) * * *

(ii) The process weighting parameter (heat input, gross output, or steam generated) that will be monitored for each averaging group;

* * * * *

(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.

* * * * *

■ 12. Section 63.10010 is amended by revising paragraphs (a)(4), (f)(3) and (4), (h)(6)(i) and (ii), (i)(5)(i)(A) and (B), (j)(1)(i), (j)(4)(i)(A) and (B), and (l) to read as follows:

§ 63.10010 What are my monitoring, installation, operation, and maintenance requirements?

(a) * * *

(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.

* * * * *

(f) * * *

(3) Calculate and record a 30-boiler operating day rolling average SO_2 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_2 emission rates in the 30 boiler operating day period.

(4) Use only unadjusted, quality-assured SO_2 concentration values in the emissions calculations; do not apply bias adjustment factors to the part 75 SO_2 data and do not use part 75 substitute data values. 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_2 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_2 emission rate for any of these hours.

* * * * *

(h) * * *

(6) * * *

(i) Any data collected during periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or quality control activities that temporarily interrupt the measurement of output data from the PM CPMS. You must report any monitoring system malfunctions or out of control periods in your annual deviation reports. You must report any monitoring system quality assurance or quality control activities per the requirements of § 63.10031(b);

(ii) 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 such periods in your annual deviation report;

* * * * *

(i) * * *

(5) * * *

(i) * * *

(A) Any data collected during periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or quality control activities that temporarily interrupt the measurement of emissions (*e.g.,* calibrations, certain audits). You must report any monitoring system malfunctions or out of control periods in your annual deviation reports. You must report any monitoring system quality assurance or quality control activities per the requirements of § 63.10031(b);

(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 such periods in your annual deviation report;

* * * * *

(j) * * *

(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.

* * * * *

(4) * * *

(i) * * *

(A) Any data collected during periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or quality control activities that temporarily interrupt the measurement of emissions (*e.g.,* calibrations, certain audits). You must report any monitoring system malfunctions or out of control periods in your annual deviation reports. You must report any monitoring system quality assurance or quality control activities per the requirements of § 63.10031(b);

(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 monitoring system malfunctions or out of control periods in your annual deviation reports. You must report any monitoring system quality assurance or quality control activities per the requirements of § 63.10031(b);

* * * * *

(l) Should you choose to rely on paragraph (2) of the definition of ‘‘startup’’ in § 63.10042 for your EGU, you must install, verify, operate, maintain, and quality assure each monitoring system necessary for demonstrating compliance with the PM or non-mercury metals work practice standards required to comply with § 63.10020(e).

(1) You shall develop a site-specific monitoring plan for PM or non-mercury metals work practice monitoring during startup periods.

(2) You shall submit the site-specific monitoring plan upon request by the Administrator.

(3) The provisions of the monitoring plan must address the following items:

(i) Monitoring system installation;

(ii) Performance and equipment specifications;

(iii) Schedule for initial and periodic performance evaluations;

(iv) Performance evaluation procedures and acceptance criteria;

(v) On-going operation and maintenance procedures; and

(vi) On-going recordkeeping and reporting procedures.

(4) You may rely on monitoring system specifications or instructions or manufacturer's specifications to address paragraphs (l)(3)(i) through (vi) of this section.

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

■ 13. Section 63.10011 is amended by revising paragraphs (b), (c), (e), and (g) to read as follows:

§ 63.10011 How do I demonstrate initial compliance with the emissions limits and work practice standards?

* * * * *

(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_2 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_2 or PM emission limit in Table 1 or 2 to this subpart.

* * * * *

(e) You must submit a Notification of Compliance Status containing the results of the initial compliance demonstration, in accordance with § 63.10030(e).

* * * * *

(g) You must follow the startup or shutdown requirements as established in Table 3 to this subpart for each coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGU.

(1) You may use the diluent cap and default gross output values, as described in § 63.10007(f), during startup periods or shutdown periods.

(2) You must operate all CMS, collect data, calculate pollutant emission rates, and record data during startup periods or shutdown periods.

(3) You must report the information as required in § 63.10031.

(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.

■ 14. Section 63.10020 is amended by revising paragraph (e) to read as follows:

§ 63.10020 How do I monitor and collect data to demonstrate continuous compliance?

* * * * *

(e) Additional requirements during startup periods or shutdown periods if you choose to rely on paragraph (2) of the definition of "startup" in § 63.10042 for your EGU.

(1) During each period of startup, you must record for each EGU:

(i) The date and time that clean fuels being combusted for the purpose of startup begins;

(ii) The quantity and heat input of clean fuel for each hour of startup;

(iii) The gross output for each hour of startup;

(iv) The date and time that non-clean fuel combustion begins; and

(v) The date and time that clean fuels being combusted for the purpose of startup ends.

(2) During each period of shutdown, you must record for each EGU:

(i) The date and time that clean fuels being combusted for the purpose of shutdown begins;

(ii) The quantity and heat input of clean fuel for each hour of shutdown;

(iii) The gross output for each hour of shutdown;

(iv) The date and time that non-clean fuel combustion ends; and

(v) The date and time that clean fuels being combusted for the purpose of shutdown ends.

(3) For PM or non-mercury HAP metals work practice monitoring during startup periods, you must monitor and collect data according to this section and the site-specific monitoring plan required by § 63.10010(l).

(i) Except for an EGU that uses PM CEMS or PM CPMS to demonstrate compliance with the PM emissions limit, or that has LEE status for filterable PM or total non-Hg HAP metals for non-liquid oil-fired EGUs (or HAP metals emissions for liquid oil-fired EGUs), or individual non-mercury metals CEMS, you must:

(A) Record temperature and combustion air flow or calculated flow as determined from combustion equations of post-combustion (exhaust) gas, as well as amperage of forced draft fan(s), upstream of the filterable PM control devices during each hour of startup.

(B) Record temperature and flow of exhaust gas, as well as amperage of any induced draft fan(s), downstream of the filterable PM control devices during each hour of startup.

(C) For an EGU with an electrostatic precipitator, record the number of fields in service, as well as each field's secondary voltage and secondary current during each hour of startup.

(D) For an EGU with a fabric filter, record the number of compartments in service, as well as the differential pressure across the baghouse during each hour of startup.

(E) For an EGU with a wet scrubber needed for filterable PM control, record the scrubber liquid to flue gas ratio and the pressure drop across the scrubber during each hour of startup.

(ii) [Reserved]

■ 15. Section 63.10021 is amended by revising paragraphs (d)(3), (e) introductory text, (e)(9), and (h)(1) to read as follows:

§ 63.10021 How do I demonstrate continuous compliance with the emission limitations, operating limits, and work practice standards?

* * * * *

(d) * * *

(3) Must conduct site-specific monitoring using CMS to demonstrate compliance with the site-specific monitoring requirements in Table 7 to this subpart pertaining to HCl and HF emissions from a liquid oil-fired EGU to ensure compliance with the HCl and HF emission limits in Tables 1 and 2 to this subpart, in accordance with the requirements of § 63.10000(c)(2)(iii). The monitoring must meet the general operating requirements provided in § 63.10020.

(e) Conduct periodic performance tune-ups of your EGU(s), as specified in paragraphs (e)(1) through (9) of this section. For your first tune-up, you may perform the burner inspection any time prior to the tune-up or you may delay the first burner inspection until the next scheduled EGU outage provided you meet the requirements of § 63.10005. Subsequently, you must perform an inspection of the burner at least once every 36 calendar months unless your EGU employs neural network combustion optimization during normal operations in which case you must perform an inspection of the burner and combustion controls at least once every 48 calendar months. If your EGU is offline when a deadline to perform the tune-up passes, you shall perform the tune-up work practice requirements within 30 days after the re-start of the affected unit.

* * * * *

(9) Report the dates of the initial and subsequent tune-ups in hard copy, as specified in § 63.10031(f)(5), until April 16, 2017. After April 16, 2017, report the date of all tune-ups electronically, in accordance with § 63.10031(f). The tune-up report date is the date when tune-up requirements in paragraphs (e)(6) and (7) of this section are completed.

* * * * *

(h) * * *

(1) You may use the diluent cap and default gross output values, as described in § 63.10007(f), during startup periods or shutdown periods.

* * * * *

■ 16. Section 63.10023 is amended by removing and reserving paragraph (b)(1) and revising paragraph (b)(2) introductory text to read as follows:

§ 63.10023 How do I establish my PM CPMS operating limit and determine compliance with it?

* * * * *

(b) * * *

(2) Determine your operating limit as follows:

* * * * *

■ 17. Section 63.10030 is amended by:

■ a. Revising paragraphs (e)(1) and (e)(7)(i);

■ b. Adding paragraph (e)(7)(iii);

■ c. Revising paragraph (e)(8); and

■ d. Adding paragraph (f).

The revisions and additions read as follows:

§ 63.10030 What notifications must I submit and when?

* * * * *

(e) * * *

(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.

* * * * *

(7) * * *

(i) A summary of the results of the annual performance tests and documentation of any operating limits that were reestablished during this test, if applicable. If you are conducting stack tests once every 3 years consistent with § 63.10005(h)(1)(i), 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 § 63.10006(i), and a statement as to whether there have been any operational changes since the last stack test that could increase emissions.

* * * * *

(iii) For each of your existing EGUs, identification of each emissions limit as specified in Table 2 to this subpart with which you plan to comply.

(A) You may switch from a mass per heat input to a mass per gross output limit (or vice-versa), provided that:

(*1*) You submit a request that identifies for each EGU or EGU emissions averaging group involved in the proposed switch both the current and proposed emission limit;

(*2*) Your request arrives to the Administrator at least 30 calendar days prior to the date that the switch is proposed to occur;

(*3*) Your request demonstrates through performance stack test results completed within 30 days prior to your submission, compliance for each EGU or EGU emissions averaging group with both the mass per heat input and mass per gross output limits;

(*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 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 demonstrate compliance with both the mass per heat input and mass per gross output emission limits for each pollutant for each EGU or EGU emissions averaging group.

(8) Identification of whether you plan to rely on paragraph (1) or (2) of the definition of ''startup'' in § 63.10042.

(i) Should you choose to rely on paragraph (2) of the definition of ''startup'' in § 63.10042 for your EGU, you shall include a report that identifies:

(A) The original EGU installation date;

(B) The original EGU design characteristics, including, but not limited to, fuel mix and PM controls;

(C) Each design PM control device efficiency established during performance testing or while operating in periods other than startup and shutdown periods;

(D) The design PM emission rate from the EGU in terms of pounds PM per MMBtu and pounds PM per hour established during performance testing or while operating in periods other than startup and shutdown periods;

(E) The design time from start of fuel combustion to necessary conditions for each PM control device startup;

(F) Each design PM control device efficiency upon startup of the PM control device, if different from the efficiency provided in paragraph (e)(8)(i)(C) of this section;

(G) Current EGU PM producing characteristics, including, but not limited to, fuel mix and PM controls, if different from the characteristics provided in paragraph (e)(8)(i)(B) of this section;

(H) Current PM control device efficiency from each PM control device, if different from the efficiency provided in paragraph (e)(8)(i)(C) of this section;

(I) Current PM emission rate from the EGU in terms of pounds PM per MMBtu and pounds per hour, if different from the rate provided in paragraph (e)(8)(i)(D) of this section;

(J) Current time from start of fuel combustion to conditions necessary for each PM control device startup, if different from the time provided in paragraph (e)(8)(i)(E) of this section; and

(K) Current PM control device efficiency upon startup of each PM control device, if different from the efficiency provided in paragraph (e)(8)(i)(H) of this section.

(ii) The report shall be prepared, signed, and sealed by a professional engineer licensed in the state where your EGU is located.

(iii) You may switch from paragraph (1) of the definition of ''startup'' in § 63.10042 to paragraph (2) of the definition of ''startup'' (or vice-versa), provided that:

(A) You submit a request that identifies for each EGU or EGU emissions averaging group involved in the proposed switch both the current definition of ''startup'' relied on and the proposed definition you plan to rely on;

(B) Your request arrives to the Administrator at least 30 calendar days prior to the date that the switch is proposed to occur;

(C) You revise and submit all other applicable plans, *e.g.,* monitoring and emissions averaging, with your submission;

(D) You maintain records of all information regarding your choice of the definition of ''startup''; and

(E) You begin to use the revised definition of ''startup'' in the next reporting period after receipt of written acknowledgement from the Administrator of the switch.

(f) You must submit the notifications in § 63.10000(h)(2) and (i)(2) that may apply to you by the dates specified.

■ 18. Section 63.10031 is amended by revising paragraphs (c) introductory text and (c)(4) and (5) and adding paragraphs (c)(6), (7), (8), and (9) to read as follows:

§ 63.10031 What reports must I submit and when?

* * * * *

(c) The compliance report must contain the information required in paragraphs (c)(1) through (9) of this section.

* * * * *

(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) If you choose to use CEMS to demonstrate compliance with numerical limits, include hourly average CEMS values and hourly average flow values during startup periods or shutdown periods. Use units of milligrams per cubic meter for PM CEMS values, micrograms per cubic meter for Hg CEMS values, and ppmv for HCl, HF, or

SO_2 CEMS values. Use units of standard cubic meters per hour on a wet basis for flow values.

(iv) If you choose to use a separate sorbent trap measurement system for startup or shutdown reporting periods, include hourly average mercury concentration values in terms of micrograms per cubic meter.

(v) If you choose to use a PM CPMS, include hourly average operating parameter values in terms of the operating limit, as well as the operating parameter to PM correlation equation.

(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.

* * * * *

■ 19. Section 63.10032 is amended by revising paragraph (f) to read as follows:

§ 63.10032 What records must I keep?

* * * * *

(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).

* * * * *

■ 20. Section 63.10042 is amended by:

■ a. Revising the definitions of ''Coal-fired electric utility steam generating unit,'' ''Coal refuse,'' ''Fossil fuel-fired,'' ''Integrated gasification combined cycle electric utility steam generating unit or IGCC,'' ''Limited-use liquid oil-fired subcategory,'' and ''Natural gas-fired electric utility steam generating unit'';

■ b. Adding, in alphabetical order, definition of ''Neural network or neural net''; and

■ c. Revising the definition of ''Oil-fired electric utility steam generating unit.''

The revisions and additions read as follows:

§ 63.10042 What definitions apply to 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 calendars 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.

* * * * *

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 calendars years on an annual rolling basis.

* * * * *

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 calendars years on an annual rolling basis.

* * * * *

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.

* * * * *

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.

* * * * *

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.

* * * * *

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 calendars years on an annual rolling basis.

* * * * *

■ 21. Revise Table 1 to subpart UUUUU of part 63 to read as follows:

TABLE 1 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED EGUS

[As stated in § 63.9991, you must comply with the following applicable emission limits:]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
1. Coal-fired unit not low rank virgin coal.	a. Filterable particulate matter (PM).	9.0E-2 lb/MWh [1]	Collect a minimum of 4 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	6.0E-2 lb/GWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E-3 lb/GWh	
	Arsenic (As)	3.0E-3 lb/GWh	
	Beryllium (Be)	6.0E-4 lb/GWh	
	Cadmium (Cd)	4.0E-4 lb/GWh	
	Chromium (Cr)	7.0E-3 lb/GWh	
	Cobalt (Co)	2.0E-3 lb/GWh	
	Lead (Pb)	2.0E-2 lb/GWh	
	Manganese (Mn)	4.0E-3 lb/GWh	
	Nickel (Ni)	4.0E-2 lb/GWh	
	Selenium (Se)	5.0E-2 lb/GWh	
	b. Hydrogen chloride (HCl)	1.0E-2 lb/MWh	For Method 26A at appendix A–8 to part 60 of this chapter, collect a minimum of 3 dscm per run. For ASTM D6348–03 [2] or Method 320 at appendix A to part 63 of this chapter, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) [3]	1.0 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	3.0E-3 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
2. Coal-fired units low rank virgin coal.	a. Filterable particulate matter (PM).	9.0E-2 lb/MWh [1]	Collect a minimum of 4 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	6.0E-2 lb/GWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E-3 lb/GWh	
	Arsenic (As)	3.0E-3 lb/GWh	
	Beryllium (Be)	6.0E-4 lb/GWh	
	Cadmium (Cd)	4.0E-4 lb/GWh	
	Chromium (Cr)	7.0E-3 lb/GWh	
	Cobalt (Co)	2.0E-3 lb/GWh	
	Lead (Pb)	2.0E-2 lb/GWh	
	Manganese (Mn)	4.0E-3 lb/GWh	
	Nickel (Ni)	4.0E-2 lb/GWh	
	Selenium (Se)	5.0E-2 lb/GWh	
	b. Hydrogen chloride (HCl)	1.0E-2 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run For ASTM D6348–03 [2] or Method 320, sample for a minimum of 1 hour.
	OR		

TABLE 1 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED EGUS—Continued

[As stated in § 63.9991, you must comply with the following applicable emission 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 . . .
	Sulfur dioxide (SO_2) [3]	1.0 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	4.0E-2 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
3. IGCC unit	a. Filterable particulate matter (PM).	7.0E-2 lb/MWh [4] 9.0E–2 lb/MWh [5].	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	4.0E-1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	2.0E-2 lb/GWh	
	Arsenic (As)	2.0E-2 lb/GWh	
	Beryllium (Be)	1.0E-3 lb/GWh	
	Cadmium (Cd)	2.0E-3 lb/GWh	
	Chromium (Cr)	4.0E-2 lb/GWh	
	Cobalt (Co)	4.0E-3 lb/GWh	
	Lead (Pb)	9.0E-3 lb/GWh	
	Manganese (Mn)	2.0E-2 lb/GWh	
	Nickel (Ni)	7.0E-2 lb/GWh	
	Selenium (Se)	3.0E-1 lb/GWh	
	b. Hydrogen chloride (HCl)	2.0E-3 lb/MWh	For Method 26A, collect a minimum of 1 dscm per run; for Method 26 at appendix A–8 to part 60 of this chapter, collect a minimum of 120 liters per run. For ASTM D6348–03 [2] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) [3]	4.0E-1 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	3.0E-3 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
4. Liquid oil-fired unit—continental (excluding limited-use liquid oil-fired subcategory units).	a. Filterable particulate matter (PM).	3.0E-1 lb/MWh [1]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	2.0E-4 lb/MWh	Collect a minimum of 2 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	1.0E-2 lb/GWh	
	Arsenic (As)	3.0E-3 lb/GWh	
	Beryllium (Be)	5.0E-4 lb/GWh	
	Cadmium (Cd)	2.0E-4 lb/GWh	
	Chromium (Cr)	2.0E-2 lb/GWh	
	Cobalt (Co)	3.0E-2 lb/GWh	
	Lead (Pb)	8.0E-3 lb/GWh	
	Manganese (Mn)	2.0E-2 lb/GWh	
	Nickel (Ni)	9.0E-2 lb/GWh	
	Selenium (Se)	2.0E-2 lb/GWh	
	Mercury (Hg)	1.0E-4 lb/GWh	For Method 30B 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.
	b. Hydrogen chloride (HCl)	4.0E-4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03 [2] or Method 320, sample for a minimum of 1 hour.
	c. Hydrogen fluoride (HF)	4.0E-4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03 [2] or Method 320, sample for a minimum of 1 hour.
5. Liquid oil-fired unit—non-continental (excluding limited-use liquid oil-fired subcategory units).	a. Filterable particulate matter (PM).	2.0E–1 lb/MWh [1]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	7.0E-3 lb/MWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.

TABLE 1 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED EGUs—Continued

[As stated in § 63.9991, you must comply with the following applicable emission 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 . . .
	Antimony (Sb)	8.0E-3 lb/GWh	
	Arsenic (As)	6.0E-2 lb/GWh	
	Beryllium (Be)	2.0E-3 lb/GWh	
	Cadmium (Cd)	2.0E-3 lb/GWh	
	Chromium (Cr)	2.0E-2 lb/GWh	
	Cobalt (Co)	3.0E-1 lb/GWh	
	Lead (Pb)	3.0E-2 lb/GWh	
	Manganese (Mn)	1.0E-1 lb/GWh	
	Nickel (Ni)	4.1E0 lb/GWh	
	Selenium (Se)	2.0E-2 lb/GWh	
	Mercury (Hg)	4.0E-4 lb/GWh	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be < ½ the standard.
	b. Hydrogen chloride (HCl)	2.0E-3 lb/MWh	For Method 26A, collect a minimum of 1 dscm per run;for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour.
	c. Hydrogen fluoride (HF)	5.0E-4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run.For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour.
6. Solid oil-derived fuel-fired unit.	a. Filterable particulate matter (PM).	3.0E-2 lb/MWh[1]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	6.0E-1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–3 lb/GWh	
	Arsenic (As)	3.0E-3 lb/GWh	
	Beryllium (Be)	6.0E-4 lb/GWh	
	Cadmium (Cd)	7.0E-4 lb/GWh	
	Chromium (Cr)	6.0E-3 lb/GWh	
	Cobalt (Co)	2.0E-3 lb/GWh	
	Lead (Pb)	2.0E-2 lb/GWh	
	Manganese (Mn)	7.0E-3 lb/GWh	
	Nickel (Ni)	4.0E-2 lb/GWh	
	Selenium (Se)	6.0E-3 lb/GWh	
	b. Hydrogen chloride (HCl)	4.0E-4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2)[3]	1.0 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	2.0E-3 lb/GWh	Hg CEMS or Sorbent trap monitoring system only.

[1] Gross output.

[2] Incorporated by reference, see § 63.14.

[3] You may not use the alternate SO_2 limit if your EGU does not have some form of FGD system (or, in the case of IGCC EGUs, some other acid gas removal system either upstream or downstream of the combined cycle block) and SO_2 CEMS installed.

[4] Duct burners on syngas; gross output.

[5] Duct burners on natural gas; gross output.

■ 22. Revise Table 2 to subpart UUUUU of part 63 to read as follows:

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: [1]]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
1. Coal-fired unit not low rank virgin coal.	a. Filterable particulate matter (PM).	3.0E-2 lb/MMBtu or 3.0E-1 lb/MWh [2].	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	5.0E-5 lb/MMBtu or 5.0E-1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E-1 lb/TBtu or 8.0E-3 lb/GWh	
	Arsenic (As)	1.1E0 lb/TBtu or 2.0E-2 lb/GWh	
	Beryllium (Be)	2.0E-1 lb/TBtu or 2.0E-3 lb/GWh	
	Cadmium (Cd)	3.0E-1 lb/TBtu or 3.0E-3 lb/GWh	
	Chromium (Cr)	2.8E0 lb/TBtu or 3.0E-2 lb/GWh	
	Cobalt (Co)	8.0E-1 lb/TBtu or 8.0E-3 lb/GWh	
	Lead (Pb)	1.2E0 lb/TBtu or 2.0E-2 lb/GWh	
	Manganese (Mn)	4.0E0 lb/TBtu or 5.0E-2 lb/GWh	
	Nickel (Ni)	3.5E0 lb/TBtu or 4.0E-2 lb/GWh	
	Selenium (Se)	5.0E0 lb/TBtu or 6.0E-2 lb/GWh	
	b. Hydrogen chloride (HCl)	2.0E-3 lb/MMBtu or 2.0E-2 lb/MWh.	For Method 26A at appendix A–8 to part 60 of this chapter, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 [3] or Method 320 at appendix A to part 63 of this chapter, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) [4]	2.0E-1 lb/MMBtu or 1.5E0 lb/MWh	SO_2 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.
2. Coal-fired unit low rank virgin coal.	a. Filterable particulate matter (PM).	3.0E-2 lb/MMBtu or 3.0E-1 lb/MWh [2].	Collect a minimum of 1 dscm per run.
	OR	OR.	
	Total non-Hg HAP metals	5.0E-5 lb/MMBtu or 5.0E-1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR.	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E-1 lb/TBtu or 8.0E-3 lb/GWh	
	Arsenic (As)	1.1E0 lb/TBtu or 2.0E-2 lb/GWh	
	Beryllium (Be)	2.0E-1 lb/TBtu or 2.0E-3 lb/GWh	
	Cadmium (Cd)	3.0E-1 lb/TBtu or 3.0E-3 lb/GWh	
	Chromium (Cr)	2.8E0 lb/TBtu or 3.0E-2 lb/GWh	
	Cobalt (Co)	8.0E-1 lb/TBtu or 8.0E-3 lb/GWh	
	Lead (Pb)	1.2E0 lb/TBtu or 2.0E-2 lb/GWh	
	Manganese (Mn)	4.0E0 lb/TBtu or 5.0E-2 lb/GWh	
	Nickel (Ni)	3.5E0 lb/TBtu or 4.0E-2 lb/GWh	
	Selenium (Se)	5.0E0 lb/TBtu or 6.0E-2 lb/GWh	

TABLE 2 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR EXISTING EGUs—Continued

[As stated in § 63.9991, you must comply with the following applicable emission limits: [1]]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	b. Hydrogen chloride (HCl)	2.0E-3 lb/MMBtu or 2.0E-2 lb/MWh.	For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26 at appendix A–8 to part 60 of this chapter, collect a minimum of 120 liters per run. For ASTM D6348–03 [3] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) [4]	2.0E-1 lb/MMBtu or 1.5E0 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	4.0E0 lb/TBtu or 4.0E-2 lb/GWh	LEE Testing for 30 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
3. IGCC unit	a. Filterable particulate matter (PM).	4.0E-2 lb/MMBtu or 4.0E-1 lb/MWh [2].	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	6.0E-5 lb/MMBtu or 5.0E-1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	1.4E0 lb/TBtu or 2.0E-2 lb/GWh	
	Arsenic (As)	1.5E0 lb/TBtu or 2.0E-2 lb/GWh	
	Beryllium (Be)	1.0E-1 lb/TBtu or 1.0E-3 lb/GWh	
	Cadmium (Cd)	1.5E-1 lb/TBtu or 2.0E-3 lb/GWh	
	Chromium (Cr)	2.9E0 lb/TBtu or 3.0E-2 lb/GWh	
	Cobalt (Co)	1.2E0 lb/TBtu or 2.0E-2 lb/GWh	
	Lead (Pb)	1.9E+2 lb/TBtu or 1.8E0 lb/GWh	
	Manganese (Mn)	2.5E0 lb/TBtu or 3.0E-2 lb/GWh	
	Nickel (Ni)	6.5E0 lb/TBtu or 7.0E-2 lb/GWh	
	Selenium (Se)	2.2E+1 lb/TBtu or 3.0E-1 lb/GWh	
	b. Hydrogen chloride (HCl)	5.0E-4 lb/MMBtu or 5.0E-3 lb/MWh.	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 [3] or Method 320, sample for a minimum of 1 hour.
	c. Mercury (Hg)	2.5E0 lb/TBtu or 3.0E-2 lb/GWh	LEE Testing for 30 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
4. Liquid oil-fired unit—continental (excluding limited-use liquid oil-fired subcategory units).	a. Filterable particulate matter (PM).	3.0E-2 lb/MMBtu or 3.0E-1 lb/MWh [2].	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	8.0E-4 lb/MMBtu or 8.0E-3 lb/MWh.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 1 dscm per run.
	Antimony (Sb)	1.3E+1 lb/TBtu or 2.0E-1 lb/GWh	
	Arsenic (As)	2.8E0 lb/TBtu or 3.0E-2 lb/GWh	
	Beryllium (Be)	2.0E-1 lb/TBtu or 2.0E-3 lb/GWh	
	Cadmium (Cd)	3.0E-1 lb/TBtu or 2.0E-3 lb/GWh	
	Chromium (Cr)	5.5E0 lb/TBtu or 6.0E-2 lb/GWh	
	Cobalt (Co)	2.1E+1 lb/TBtu or 3.0E-1 lb/GWh	
	Lead (Pb)	8.1E0 lb/TBtu or 8.0E-2 lb/GWh	
	Manganese (Mn)	2.2E+1 lb/TBtu or 3.0E-1 lb/GWh	
	Nickel (Ni)	1.1E+2 lb/TBtu or 1.1E0 lb/GWh	

TABLE 2 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR EXISTING EGUS—Continued

[As stated in § 63.9991, you must comply with the following applicable emission limits: [1]]

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 . . .
	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 < ½ 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 [3] 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 [3] 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 [2].	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	6.0E-4 lb/MMBtu or 7.0E-3 lb/MWh.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	2.2E0 lb/TBtu or 2.0E-2 lb/GWh	
	Arsenic (As)	4.3E0 lb/TBtu or 8.0E-2 lb/GWh	
	Beryllium (Be)	6.0E-1 lb/TBtu or 3.0E-3 lb/GWh	
	Cadmium (Cd)	3.0E-1 lb/TBtu or 3.0E-3 lb/GWh	
	Chromium (Cr)	3.1E+1 lb/TBtu or 3.0E-1 lb/GWh	
	Cobalt (Co)	1.1E+2 lb/TBtu or 1.4E0 lb/GWh	
	Lead (Pb)	4.9E0 lb/TBtu or 8.0E-2 lb/GWh	
	Manganese (Mn)	2.0E+1 lb/TBtu or 3.0E-1 lb/GWh	
	Nickel (Ni)	4.7E+2 lb/TBtu or 4.1E0 lb/GWh	
	Selenium (Se)	9.8E0 lb/TBtu or 2.0E-1 lb/GWh	
	Mercury (Hg)	4.0E-2 lb/TBtu or 4.0E-4 lb/GWh	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be < ½ the standard.
	b. Hydrogen chloride (HCl)	2.0E-4 lb/MMBtu or 2.0E-3 lb/MWh.	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 [3] or Method 320, sample for a minimum of 2 hours.
	c. Hydrogen fluoride (HF)	6.0E-5 lb/MMBtu or 5.0E-4 lb/MWh.	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03 [3] or Method 320, sample for a minimum of 2 hours.
6. Solid oil-derived fuel-fired unit	a. Filterable particulate matter (PM).	8.0E-3 lb/MMBtu or 9.0E-2 lb/MWh [2].	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	4.0E-5 lb/MMBtu or 6.0E-1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E-1 lb/TBtu or 7.0E-3 lb/GWh	
	Arsenic (As)	3.0E-1 lb/TBtu or 5.0E-3 lb/GWh	
	Beryllium (Be)	6.0E-2 lb/TBtu or 5.0E-4 lb/GWh	

TABLE 2 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR EXISTING EGUS—Continued

[As stated in § 63.9991, you must comply with the following applicable emission limits: [1]]

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 . . .
	Cadmium (Cd)	3.0E-1 lb/TBtu or 4.0E-3 lb/GWh	
	Chromium (Cr)	8.0E-1 lb/TBtu or 2.0E-2 lb/GWh	
	Cobalt (Co)	1.1E0 lb/TBtu or 2.0E-2 lb/GWh	
	Lead (Pb)	8.0E-1 lb/TBtu or 2.0E-2 lb/GWh	
	Manganese (Mn)	2.3E0 lb/TBtu or 4.0E-2 lb/GWh	
	Nickel (Ni)	9.0E0 lb/TBtu or 2.0E-1 lb/GWh	
	Selenium (Se)	1.2E0 lb/Tbtu or 2.0E-2 lb/GWh	
	b. Hydrogen chloride (HCl)	5.0E-3 lb/MMBtu or 8.0E-2 lb/MWh.	For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 [3] or Method 320, sample for a minimum of 1 hour.
	OR Sulfur dioxide (SO_2) [4]	3.0E-1 lb/MMBtu or 2.0E0 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	2.0E-1 lb/TBtu or 2.0E-3 lb/GWh	LEE Testing for 30 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B run or Hg CEMS or sorbent trap monitoring system only.

[1] 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 two.
[2] Gross output.
[3] Incorporated by reference, see § 63.14.
[4] You may not use the alternate SO_2 limit if your EGU does not have some form of FGD system and SO_2 CEMS installed.

■ 23. Revise Table 3 to subpart UUUUU of part 63 to read as follows:

TABLE 3 TO SUBPART UUUUU OF PART 63—WORK PRACTICE STANDARDS

[As stated in § 63.9991, you must comply with the following applicable work practice standards:]

If your EGU is . . .	You must meet the following . . .
1. An existing EGU	Conduct a tune-up of the EGU burner and combustion controls at least each 36 calendar months, or each 48 calendar months if neural network combustion optimization software is employed, as specified in § 63.10021(e).
2. A new or reconstructed EGU.	Conduct a tune-up of the EGU burner and combustion controls at least each 36 calendar months, or each 48 calendar months if neural network combustion optimization software is employed, as specified in § 63.10021(e).
3. A coal-fired, liquid oil-fired (excluding limited-use liquid oil-fired subcategory units), or solid oil-derived fuel-fired EGU during startup.	a. You have the option of complying using either of the following work practice standards: (1) If you choose to comply using paragraph (1) of the definition of "startup" in § 63.10042, 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). (2) If you choose to comply using paragraph (2) of the definition of "startup" in § 63.10042, you must operate all CMS during startup. You must also collect appropriate data, and you must calculate the pollutant emission rate for each hour of startup. For startup of an EGU, you must use one or a combination of the clean fuels defined in § 63.10042 to the maximum extent possible, taking into account considerations such as boiler or control device integrity, throughout the startup period. You must have sufficient clean fuel capacity to engage and operate your PM control device within one hour of adding coal, residual oil, or solid oil-derived fuel to the unit. You must meet the startup period work practice requirements as identified in § 63.10020(e). Once you start firing coal, residual oil, or solid oil-derived fuel, you must vent emissions to the main stack(s). You must comply with the applicable emission limits beginning with the hour after startup ends. You must engage and operate your particulate matter control(s) within 1 hour of first firing of coal, residual oil, or solid oil-derived fuel.

TABLE 3 TO SUBPART UUUUU OF PART 63—WORK PRACTICE STANDARDS—Continued

[As stated in § 63.9991, you must comply with the following applicable work practice standards:]

If your EGU is . . .	You must meet the following . . .
	You must start all other applicable control devices as expeditiously as possible, considering safety and manufacturer/supplier recommendations, but, in any case, when necessary to comply with other standards made applicable to the EGU by a permit limit or a rule other than this Subpart that require operation of the control devices. b. Relative to the syngas not fired in the combustion turbine of an IGCC EGU during startup, you must either: (1) Flare the syngas, or (2) route the syngas to duct burners, which may need to be installed, and route the flue gas from the duct burners to the heat recovery steam generator. c. If you choose to use just one set of sorbent traps to demonstrate compliance with the applicable Hg emission limit, you must comply with the limit at all times; otherwise, you must comply with the applicable emission limit at all times except for startup and shutdown periods. d. You must collect monitoring data during startup periods, as specified in § 63.10020(a) and (e). You must keep records during startup periods, as provided in §§ 63.10032 and 63.10021(h). You must provide reports concerning activities and startup periods, as specified in §§ 63.10011(g), 63.10021(i), and 63.10031.
4. A coal-fired, liquid oil-fired (excluding limited-use liquid oil-fired subcategory units), or solid oil-derived fuel-fired EGU during shutdown.	You must operate all CMS during shutdown. You must also collect appropriate data, and you must calculate the pollutant emission rate for each hour of shutdown for those pollutants for which a CMS is used. While firing coal, residual oil, or solid oil-derived fuel during shutdown, you must vent emissions to the main stack(s) and operate all applicable control devices and continue to operate those control devices after the cessation of coal, residual oil, or solid oil-derived fuel being fed into the EGU and for as long as possible thereafter considering operational and safety concerns. In any case, you must operate your controls when necessary to comply with other standards made applicable to the EGU by a permit limit or a rule other than this Subpart and that require operation of the control devices. If, in addition to the fuel used prior to initiation of shutdown, another fuel must be used to support the shutdown process, that additional fuel must be one or a combination of the clean fuels defined in § 63.10042 and must be used to the maximum extent possible, taking into account considerations such as not compromising boiler or control device integrity. Relative to the syngas not fired in the combustion turbine of an IGCC EGU during shutdown, you must either: (1) Flare the syngas, or (2) route the syngas to duct burners, which may need to be installed, and route the flue gas from the duct burners to the heat recovery steam generator. 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.

■ 24. Revise Table 4 to subpart UUUUU of part 63 to read as follows:

TABLE 4 TO SUBPART UUUUU OF PART 63 — OPERATING LIMITS FOR EGUS

[As stated in § 63.9991, you must comply with the applicable operating limits:]

If you demonstrate compliance using . . .	You must meet these operating limits . . .
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).

■ 25. Revise Table 5 to subpart UUUUU of part 63 to read as follows:

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: [1]]

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 . . . [2]
1. Filterable Particulate matter (PM).	Emissions Testing	a. Select sampling ports location and the number of traverse points.	Method 1 at appendix A–1 to part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2A, 2C, 2F, 2G or 2H at appendix A–1 or A–2 to part 60 of this chapter.

TABLE 5 TO SUBPART UUUUU OF PART 63—PERFORMANCE TESTING REQUIREMENTS—Continued

[As stated in § 63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources: [1]]

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 . . .[2]
		c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B at appendix A–2 to part 60 of this chapter, or ANSI/ASME PTC 19.10–1981.[3]
		d. Measure the moisture content of the stack gas.	Method 4 at appendix A–3 to part 60 of this chapter.
		e. Measure the filterable PM concentration.	Method 5 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 front half temperature shall be 160° ± 14° C (320° ± 25° F).
		f. Convert emissions concentration to lb/MMBtu or lb/MWh emissions rates.	Method 19 F-factor methodology at appendix A–7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
	OR	OR.	
	PM CEMS	a. Install, certify, operate, and maintain the PM CEMS.	Performance Specification 11 at appendix B to part 60 of this chapter and Procedure 2 at appendix F to part 60 of this chapter.
		b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems.	Part 75 of this chapter and § 63.10010(a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates.	Method 19 F-factor methodology at appendix A–7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
2. Total or individual non-Hg HAP metals.	Emissions Testing	a. Select sampling ports location and the number of traverse points..	Method 1 at appendix A–1 to part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2A, 2C, 2F, 2G or 2H at appendix A–1 or A–2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B at appendix A–2 to part 60 of this chapter, or ANSI/ASME PTC 19.10–1981.[3]
		d. Measure the moisture content of the stack gas.	Method 4 at appendix A–3 to part 60 of this chapter.
		e. Measure the HAP metals emissions concentrations and determine each individual HAP metals emissions concentration, as well as the total filterable HAP metals emissions concentration and total HAP metals emissions concentration.	Method 29 at appendix A–8 to part 60 of this chapter. For liquid oil-fired units, Hg is included in HAP metals and you may use Method 29, Method 30B at appendix A–8 to part 60 of this chapter; for Method 29, you must report the front half and back half results separately. When using Method 29, report metals matrix spike and recovery levels.
		f. Convert emissions concentrations (individual HAP metals, total filterable HAP metals, and total HAP metals) to lb/MMBtu or lb/MWh emissions rates.	Method 19 F-factor methodology at appendix A–7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
3. Hydrogen chloride (HCl) and hydrogen fluoride (HF).	Emissions Testing	a. Select sampling ports location and the number of traverse points..	Method 1 at appendix A–1 to part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2A, 2C, 2F, 2G or 2H at appendix A–1 or A–2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B at appendix A–2 to part 60 of this chapter, or ANSI/ASME PTC 19.10–1981.[3]
		d. Measure the moisture content of the stack gas.	Method 4 at appendix A–3 to part 60 of this chapter.

TABLE 5 TO SUBPART UUUUU OF PART 63—PERFORMANCE TESTING REQUIREMENTS—Continued

[As stated in § 63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources: [1]]

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 . . .[2]
		e. Measure the HCl and HF emissions concentrations.	Method 26 or Method 26A at appendix A–8 to part 60 of this chapter or Method 320 at appendix A to part 63 of this chapter or ASTM 6348–03[3] with (1) the following conditions when using ASTM D6348–03: (A) The test plan preparation and implementation in the Annexes to ASTM D6348–03, Sections A1 through A8 are mandatory; (B) For ASTM D6348–03 Annex A5 (Analyte Spiking Technique), the percent (%) R must be determined for each target analyte (see Equation A5.5); (C) For the ASTM D6348–03 test data to be acceptable for a target analyte, %R must be 70% ≥ R ≤ 130%; and

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:

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

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 . . .[2] (cont'd)
			(2) spiking levels nominally no greater than two times the level corresponding to the applicable emission limit. Method 26A must be used if there are entrained water droplets in the exhaust stream.
		f. Convert emissions concentration to lb/MMBtu or lb/MWh emissions rates.	Method 19 F-factor methodology at appendix A–7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
	OR	OR.	
	HCl and/or HF CEMS	a. Install, certify, operate, and maintain the HCl or HF CEMS.	Appendix B of this subpart.
		b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems.	Part 75 of this chapter and § 63.10010(a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates.	Method 19 F-factor methodology at appendix A–7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
4. Mercury (Hg)	Emissions Testing	a. Select sampling ports location and the number of traverse points.	Method 1 at appendix A–1 to part 60 of this chapter or Method 30B at Appendix A–8 for Method 30B point selection.
		b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2A, 2C, 2F, 2G or 2H at appendix A–1 or A–2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B at appendix A–1 to part 60 of this chapter, or ANSI/ASME PTC 19.10–1981.[3]

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 . . .[2] (cont'd)
		d. Measure the moisture content of the stack gas.	Method 4 at appendix A–3 to part 60 of this chapter.
		e. Measure the Hg emission concentration.	Method 30B at appendix A–8 to part 60 of this chapter, ASTM D6784,[3] 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.
		f. Convert emissions concentration to lb/TBtu or lb/GWh emission rates.	Method 19 F-factor methodology at appendix A–7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
	OR	OR.	
	Hg CEMS	a. Install, certify, operate, and maintain the CEMS.	Sections 3.2.1 and 5.1 of appendix A of this subpart.
		b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems.	Part 75 of this chapter and § 63.10010(a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/TBtu or lb/GWh emissions rates.	Section 6 of appendix A to this subpart.
	OR	OR.	
	Sorbent trap monitoring system.	a. Install, certify, operate, and maintain the sorbent trap monitoring system.	Sections 3.2.2 and 5.2 of appendix A to this subpart.
		b. Install, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems.	Part 75 of this chapter and § 63.10010(a), (b), (c), and (d).
		c. Convert emissions concentrations to 30 boiler operating day rolling average lb/TBtu or lb/GWh emissions rates.	Section 6 of appendix A to this subpart.
	OR	OR.	
	LEE testing	a. Select sampling ports location and the number of traverse points.	Single point located at the 10% centroidal area of the duct at a port location per Method 1 at appendix A–1 to part 60 of this chapter or Method 30B at Appendix A–8 for Method 30B point selection.
		b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2A, 2C, 2F, 2G, or 2H at appendix A–1 or A–2 to part 60 of this chapter or flow monitoring system certified per appendix A of this subpart.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B at appendix A–1 to part 60 of this chapter, or ANSI/ASME PTC 19.10–1981,[3] or diluent gas monitoring systems certified according to part 75 of this chapter.
		d. Measure the moisture content of the stack gas.	Method 4 at appendix A–3 to part 60 of this chapter, or moisture monitoring systems certified according to part 75 of this chapter.
		e. Measure the Hg emission concentration.	Method 30B at appendix A–8 to part 60 of this chapter; perform a 30 operating day test, with a maximum of 10 operating days per run (*i.e.,* per pair of sorbent traps) or sorbent trap monitoring system or Hg CEMS certified per appendix A of this subpart.
		f. Convert emissions concentrations from the LEE test to lb/TBtu or lb/GWh emissions rates.	Method 19 F-factor methodology at appendix A–7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
		g. Convert average lb/TBtu or lb/GWh Hg emission rate to lb/year, if you are attempting to meet the 29.0 lb/year threshold.	Potential maximum annual heat input in TBtu or potential maximum electricity generated in GWh.

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 . . .[2] (cont'd)
5. Sulfur dioxide (SO_2)	SO_2 CEMS	a. Install, certify, operate, and maintain the CEMS.	Part 75 of this chapter and § 63.10010(a) and (f).
		b. Install, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems.	Part 75 of this chapter and § 63.10010(a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates.	Method 19 F-factor methodology at appendix A–7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).

[1] Regarding emissions data collected during periods of startup or shutdown, see §§ 63.10020(b) and (c) and 63.10021(h).
[2] See Tables 1 and 2 to this subpart for required sample volumes and/or sampling run times.
[3] Incorporated by reference, see § 63.14.

■ 26. Revise Table 6 to subpart UUUUU of part 63 to read as follows:

TABLE 6 TO SUBPART UUUUU OF PART 63—ESTABLISHING PM CPMS OPERATING LIMITS

[As stated in § 63.10007, you must comply with the following requirements for establishing operating limits:]

If you have an applicable emission limit for . . .	And you choose to establish PM CPMS operating limits, you must . . .	And . . .	Using . . .	According to the following procedures . . .
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.	1. Collect PM CPMS output data during the entire period of the performance tests. 2. Record the average hourly PM CPMS output for each test run in the performance test. 3. Determine the PM CPMS operating limit in accordance with the requirements of § 63.10023(b)(2) from data obtained during the performance test demonstrating compliance with the filterable PM or HAP metals emissions limitations.

■ 27. Revise Table 8 to subpart UUUUU of part 63 to read as follows:

TABLE 8 TO SUBPART UUUUU OF PART 63—REPORTING REQUIREMENTS

[As stated in § 63.10031, you must comply with the following requirements:]

You must submit a	The report must contain . . .	You must submit the report . . .
1. Compliance report.	a. Information required in § 63.10031(c)(1) through (9); and b. If there are no deviations from any emission limitation (emission limit and operating limit) that applies to you and there are no deviations from the requirements for work practice standards in Table 3 to this subpart that apply to you, a statement that there were no deviations from the emission limitations and work practice standards during the reporting period. If there were no periods during which the CMSs, including continuous emissions monitoring system, and operating parameter monitoring systems, were out-of-control as specified in § 63.8(c)(7), a statement that there were no periods during which the CMSs were out-of-control during the reporting period; and. c. If you have a deviation from any emission limitation (emission limit and operating limit) or work practice standard during the reporting period, the report must contain the information in § 63.10031(d). If there were periods during which the CMSs, including continuous emissions monitoring systems and continuous parameter monitoring systems, were out-of-control, as specified in § 63.8(c)(7), the report must contain the information in § 63.10031(e)..	Semiannually according to the requirements in § 63.10031(b).

■ 28. Revise Table 9 to subpart UUUUU of part 63 to read as follows:

TABLE 9 TO SUBPART UUUUU OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART UUUUU

[As stated in § 63.10040, you must comply with the applicable General Provisions according to the following:]

Citation	Subject	Applies to subpart UUUUU
§ 63.1	Applicability	Yes.
§ 63.2	Definitions	Yes. Additional terms defined in § 63.10042.
§ 63.3	Units and Abbreviations	Yes.
§ 63.4	Prohibited Activities and Circumvention	Yes.
§ 63.5	Preconstruction Review and Notification Requirements.	Yes.
§ 63.6(a), (b)(1) 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 information required per § 63.10030(e)(1) through (e)(6) and (e)(8).
§ 63.10(a), (b)(1), (c), (d)(1) and (2), (e), and (f)	Recordkeeping and Reporting Requirements	Yes, except for the requirements to submit written reports under § 63.10(e)(3)(v).
§ 63.10(b)(2)(i)	Recordkeeping of occurrence and duration of startups and shutdowns.	No.
§ 63.10(b)(2)(ii)	Recordkeeping of malfunctions	No. See § 63.10001 for recordkeeping of (1) occurrence and duration and (2) actions taken during malfunction.
§ 63.10(b)(2)(iii)	Maintenance records	Yes.
§ 63.10(b)(2)(iv)	Actions taken to minimize emissions during SSM.	No.
§ 63.10(b)(2)(v)	Actions taken to minimize emissions during SSM.	No.
§ 63.10(b)(2)(vi)	Recordkeeping for CMS malfunctions	Yes.
§ 63.10(b)(2)(vii) through (ix)	Other CMS requirements	Yes.
§ 63.10(b)(3) and (d)(3) through (5)		No.
§ 63.10(c)(7)	Additional recordkeeping requirements for CMS—identifying exceedances and excess emissions.	Yes.
§ 63.10(c)(8)	Additional recordkeeping requirements for CMS—identifying exceedances and excess emissions.	Yes.
§ 63.10(c)(10)	Recording nature and cause of malfunctions	No. See § 63.10032(g) and (h) for malfunctions recordkeeping requirements.
§ 63.10(c)(11)	Recording corrective actions	No. See § 63.10032(g) and (h) for malfunctions recordkeeping requirements.
§ 63.10(c)(15)	Use of SSM Plan	No.
§ 63.10(d)(5)	SSM reports	No. See § 63.10021(h) and (i) for malfunction reporting requirements.
§ 63.11	Control Device Requirements	No.
§ 63.12	State Authority and Delegation	Yes.
§§ 63.13 through 63.16	Addresses, Incorporation by Reference, Availability of Information, Performance Track Provisions.	Yes.

TABLE 9 TO SUBPART UUUUU OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART UUUUU—Continued

[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(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.

■ 29. Appendix A to subpart UUUUU of part 63 is amended by revising paragraphs 3.2.1.2.1, 4.1.1.1, and 4.1.1.3, table A–1, paragraphs 4.1.1.5, 4.1.1.5.2, 5.1.2.1, and 5.1.2.3, table A–2, and paragraphs 5.2.1, 6.2.2.3, and 7.1.8.5 and adding paragraph 7.1.2.6 to read as follows:

Appendix A to Subpart UUUUU of Part 63—Hg Monitoring Provisions

* * * * *

3. Mercury Emissions Measurement Methods

* * * * *

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^0 and $HgCl_2$ are required. Special reagents and equipment may be needed to prepare the Hg^0 and $HgCl_2$ gas standards (*e.g.,* NIST-traceable solutions of $HgCl_2$ and gas generators equipped with mass flow controllers).

* * * * *

4. Certification and Recertification Requirements

* * * * *

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.

* * * * *

4.1.1.3 *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_g CEMS

For this required certification test . . .	The main performance specification [1] is . . .	The alternate performance specification [1] is . . .	And the conditions of the alternate specification are . . .
7-day calibration error test [2 6]	$\lvert R - A \rvert \le 5.0\%$ of span value, for both the zero and upscale gases, on each of the 7 days..	$\lvert R - A \rvert \le 1.0$ µg/scm	The alternate specification may be used on any day of the test.
Linearity check [3 6]	$\lvert R - A_{avg} \rvert \le 10.0\%$ of the reference gas concentration at each calibration gas level (low, mid, or high)..	$\lvert R - A_{avg} \rvert \le 0.8$ µg/scm	The alternate specification may be used at any gas level.
3-level system integrity check [4]	$\lvert R - A_{avg} \rvert \le 10.0\%$ of the reference gas concentration at each calibration gas level..	$\lvert R - A_{avg} \rvert \le 0.8$ µg/scm	The alternate specification may be used at any gas level.

TABLE A–1—REQUIRED CERTIFICATION TESTS AND PERFORMANCE SPECIFICATIONS FOR H_g CEMS—Continued

For this required certification test . . .	The main performance specification [1] is . . .	The alternate performance specification [1] is . . .	And the conditions of the alternate specification are . . .
RATA	20.0% RA	$\lvert RM_{avg} - C_{avg}\rvert + \lvert CC\rvert \leq 0.5$ µg/scm [7].	$RM_{avg} < 2.5$µg/scm
Cycle time test [5]	15 minutes where the stability criteria are readings change by < 2.0% of span *or* by ≤ 0.5 µg/scm, for 2 minutes..		

[1] Note that $\lvert R - A\rvert$ is the absolute value of the difference between the reference gas value and the analyzer reading. $\lvert R - A_{avg}\rvert$ is the absolute value of the difference between the reference gas concentration and the average of the analyzer responses, at a particular gas level.
[2] Use elemental Hg standards; a mid-level or high-level upscale gas may be used.
[3] Use elemental Hg standards.
[4] Use oxidized Hg standards.
[5] 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.
[6] 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.
[7] Note that $\lvert RM_{avg} - C_{avg}\rvert$ 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.

* * * * *

4.1.1.5 *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.

$$RD = \frac{|C_a - C_b|}{C_a + C_b} \times 100 \quad (Eq.\ A-1)$$

Where:

RD = Relative Deviation between the Hg concentrations of samples ''a'' and ''b'' (percent),

C_a = Hg concentration of Hg sample ''a'' (µ g/dscm), and

C_b = Hg concentration of Hg sample ''b'' (µ g/dscm).

* * * * *

4.1.1.5.2 *Calculation of RATA Results.* Calculate the relative accuracy (RA) of the monitoring system, on a µ g/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) including the option to substitute the emission limit value (in this case the equivalent concentration) in the denominator of Equation 2–6 in place of the average RM value when the average emissions for the test are less than 50 percent of the applicable emissions limit. 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.

* * * * *

5. Ongoing Quality Assurance (QA) and Data Validation

* * * * *

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.

* * * * *

5.1.2.3 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).

* * * * *

TABLE A–2—ON-GOING QA TEST REQUIREMENTS FOR H_g CEMS

Perform this type of QA test . . .	At this frequency . . .	With these qualifications and exceptions . . .	Acceptance criteria . . .
Calibration error test[5]	Daily	• Use either a mid- or high-level gas. • Use elemental Hg • Calibrations are not required when the unit is not in operation..	$\|R - A\| \leq 5.0\%$ of span value *or* $\|R - A\| \leq 1.0$ µg/scm.
Single-level system integrity check.	Weekly[1]	• Use oxidized Hg—either mid- or high-level.	$\|R - A_{avg}\| \leq 10.0\%$ of the reference gas value *or* $\|R - A_{avg}\| \leq 0.8$ µg/scm.
Linearity check *or* 3-level system integrity check.	Quarterly[3]	• Required in each "QA operating quarter"[2] and no less than once every 4 calendar quarters. • 168 operating hour grace period available. • Use elemental Hg for linearity check. • Use oxidized Hg for system integrity check.	$\|R - A_{avg}\| \leq 10.0\%$ of the reference gas value, at each calibration gas level *or* $\|R - A_{avg}\| \leq 0.8$ µg/scm.
RATA	Annual[4]	• Test deadline may be extended for "non-QA operating quarters," up to a maximum of 8 quarters from the quarter of the previous test.. • 720 operating hour grace period available.	≤20.0% RA when $C_{avg} \geq 2.5$ µg/scm *or* $\|RM_{avg} - C_{avg}\| + \|CC\| \leq 0.5$ µgµ/scm, if $RM_{avg} < 2.5$ µg/scm.

[1] "Weekly" means once every 7 operating days.
[2] A "QA operating quarter" is a calendar quarter with at least 168 unit or stack operating hours.
[3] "Quarterly" means once every QA operating quarter.
[4] "Annual" means once every four QA operating quarters.
[5] 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.

* * * * *

5.2.1 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.

* * * * *

6. Data Reductions and Calculations

* * * * *

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.

$$\bar{E}_o = \frac{\sum_{h=1}^{n} E_{ho}}{n} \quad (Eq.\ A-5)$$

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

* * * * *

7.1.2.6 The EGUs that constitute an emissions averaging group.

* * * * *

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.

* * * * *

■ 30. Appendix B to subpart UUUUU of part 63 is amended by:
■ a. Revising paragraphs 2.1 and 2.3;
■ b. Adding paragraphs 2.3.1 and 2.3.2;
■ c. Revising paragraphs 3.1 and 3.2 and adding paragraph 3.3;
■ d. Adding introductory text to section 5;
■ e. Revising paragraphs 5.1, 5.1.2, 5.2, and 5.3;
■ f. Adding paragraphs 5.4, 5.4.1, 5.4.2, 5.4.2.1, 5.4.2.2, 5.4.2.2.1, 5.4.2.2.2, 5.4.2.3, 5.4.2.3.1, 5.4.2.3.2, 5.4.2.3.3, and 5.4.3; and
■ g. Revising section 8 introductory text and paragraph 9.3.2.

The revisions and additions read as follows:

Appendix B to Subpart UUUUU of Part 63—HCl and HF Monitoring Provisions

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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.

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2.3 *FTIR 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

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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.

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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.

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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.

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5.1.2 On a quarterly basis, you must conduct a gas audit of the HCl and/or HF CEMS as described in section 3.1.1 of this appendix. For the purposes of this appendix, ''quarterly'' means once every ''QA operating quarter'' (as defined in section 3.1.20 of appendix A to this subpart). You have the option to use HCl gas in lieu of HF gas for conducting this audit on an HF CEMS. To the extent practicable, perform consecutive quarterly gas audits at least 30 days apart. The initial quarterly audit is due in the first QA operating quarter following the calendar quarter in which certification testing of the CEMS is successfully completed. Up to three consecutive exemptions from the quarterly audit requirement are allowed for ''non-QA operating quarters'' (*i.e.,* calendar quarters in which there are less than 168 unit or stack operating hours). However, no more than four consecutive calendar quarters may elapse without performing a gas audit, except as otherwise provided in section 5.4.2.2.1 of this appendix.

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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.

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5.4 *Data Validation.*

5.4.1 *Out-of-Control Periods.* An HCl or HF CEMS that is used to provide data under this appendix is considered to be out-of-control, and data from the CEMS may not be reported as quality-assured, when any acceptance criteria for a required QA test is not met. The HCl or HF CEMS is also considered to be out-of-control when a required QA test is not performed on schedule or within an allotted grace period. To end an out-of-control period, the QA test that was either failed or not done on time must be performed and passed. Out-of-control periods are counted as hours of monitoring system downtime.

5.4.2 *Grace Periods.* For the purposes of this appendix, a ''grace period'' is defined as a specified number of unit or stack operating hours after the deadline for a required quality-assurance test of a continuous monitor has passed, in which the test may be performed and passed without loss of data.

5.4.2.1 For the monitoring systems described in section 5.3 of this appendix, a 168 unit or stack operating hour grace period is available for quarterly linearity checks, and a 720 unit or stack operating hour grace period is available for RATAs, as provided, respectively, in sections 2.2.4 and 2.3.3 of appendix B to part 75 of this chapter.

5.4.2.2 For the purposes of this appendix, if the deadline for a required gas audit/data accuracy assessment or RATA of an HCl CEMS cannot be met due to circumstances beyond the control of the owner or operator:

5.4.2.2.1 A 168 unit or stack operating hour grace period is available in which to perform the gas audit or other quarterly data accuracy assessment; or

5.4.2.2.2 A 720 unit or stack operating hour grace period is available in which to perform the RATA.

5.4.2.3 If a required QA test is performed during a grace period, the deadline for the next test shall be determined as follows:

5.4.2.3.1 For a gas audit or RATA of the monitoring systems described in sections 5.1 and 5.2 of this appendix, determine the deadline for the next gas audit or RATA (as applicable) in accordance with section 2.2.4(b) or 2.3.3(d) of appendix B to part 75 of this chapter; treat a gas audit in the same manner as a linearity check.

5.4.2.3.2 For the gas audit or other quarterly data accuracy assessment of an HCl or HF CEMS, the grace period test only satisfies the audit requirement for the calendar quarter in which the test was originally due. If the calendar quarter in which the grace period audit is performed is a QA operating quarter, an additional gas audit/data accuracy assessment is required for that quarter.

5.4.2.3.3 For the RATA of an HCl or HF CEMS, the next RATA is due within three QA operating quarters after the calendar quarter in which the grace period test is performed.

5.4.3 *Conditional Data Validation.* For recertification and diagnostic testing of the monitoring systems that are used to provide data under this appendix, the conditional data validation provisions in § 75.20(b)(3)(ii) through (ix) of this chapter may be used to avoid or minimize data loss. The allotted window of time to complete calibration tests and RATAs shall be as specified in § 75.20(b)(3)(iv) of this chapter; the allotted window of time to complete a quarterly gas audit or data accuracy assessment shall be the same as for a linearity check (*i.e.,* 168 unit or stack operating hours).

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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.

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9. Data Reduction and Calculations

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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 9.43×10^{-8} lb/scf-ppm (for HCl) or 5.18×10^{-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.

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