CONTENTS

Appendix BMP	Best Management Practices Plan;
Appendix CC	Common Conditions;
Appendix CEMS	Continuous Emissions Monitoring System (CEMS) Requirements;
Appendix CF	Citation Formats and Glossary of Common Terms;
Appendix CTR	Common Testing Requirements;
Appendix Da	NSPS, 40 CFR 60, Subpart Da – Standards of Performance for Electric Utility Steam Generating Units for Which Construction Is Commenced After September 18, 1978;
Appendix F	40 CFR 75, Appendix F, Section 5 – Measurement of Boiler Heat Input Rate;
Appendix GC	General Conditions;
Appendix GP	Identification of General Provisions – NSPS 40 CFR 60, Subpart A and NESHAP 40 CFR 63, Subpart A;
Appendix IIII	NSPS, Subpart IIII – Stationary Compression Ignition Internal Combustion Engines; and,
Appendix ZZZZ	NESHAP, Subpart ZZZZ – Stationary Reciprocating Internal Combustion Engines (RICE).

DRAFT

PRELIMINARY BEST MANAGEMENT PRACTICES (BMP) PLAN FOR MINIMIZATION OF FUGITIVE DUST, PILE MANAGEMENT AND FIRE PREVENTION

The permittee shall comply with this BMP plan and any update hereto.
[Rule 62-4.070, F.A.C. Reasonable Assurance and Rule 62-296.320(4)(c), F.A.C.]

{Permitting Note: The preliminary BMP plan will be updated by GREC as the engineering of the Biomass Receiving, Handling, Storage and Processing emission unit (EU-001) is finalized. The final BMP plan must be submitted to the Compliance Authority no later than 180 days before the GREC facility becomes operational.}

Best Management Practice – Clean Woody Biomass Fuel Definition and Limitations for the GREC
1. In-forest residue and slash: Tops, limbs, whole tree material and other residues from soft and hardwoods that result from traditional silvicultural harvests. 2. Mill residue: Saw dust, bark, shavings and kerf waste from cutting/milling whole green trees; fines from planning kiln-dried lumber; wood waste material generated by primary wood products industries such as round-offs, end cuts, sticks, pole ends; and reject lumber as well as residue material from the construction of wood trusses and pallets. 3. Pre-commercial tree trimmings and understory clearings: Tops, limbs, whole tree material and other residues that result from the cutting or removal of certain, smaller trees from a stand to regulate the number, quality, and distribution of the remaining commercial trees; forest understory which includes smaller trees, bushes, and saplings 4. Storm, fire and disease debris: Tops, limbs, whole tree material and other residues that are damaged due to storms, fires or infectious diseases. 5. Urban wood waste: Tree parts and/or branches generated by landscaping contractors and power line/roadway clearance contractors that have been cut down for land development or right-of-way clearing purposes. 6. Recycled industrial wood: Wood derived from used pallets packing crates; and dunnage disposed by commercial or industrial users. 7. Supplementary fuel material: Herbaceous plant matter; clean agricultural residues (i.e., rice hulls, straw, etc.; no animal wastes or manure); and whole tree chips and pulpwood chips. 8. Prohibited Materials: The following items are not considered woody biomass and are expressly prohibited: a) those materials that are prohibited by state or federal law; b) plastics; c) woody biomass that has been chemically treated or processed; d) yard trash; e) municipal solid waste; f) paper; g) treated wood such as CCA or creosote; h) painted wood; and i) wood wastes from landfills.

DRAFT

Best Management Practice – Minimization of Fugitive Dust
1. Conveyor systems and associated drop points for biomass material shall be covered or partially enclosed. 2. The incoming trucks will dump into in ground receiving hoppers which are covered for dust control. The receiving hoppers will be covered by a divided enclosure equipped with roll up entry doors, slitted curtains at the exit doors and stilling curtains in the upper roof area. 3. Equipment inside the enclosed fuel processing building (Screen/Hog Building), including screens and hogs will be equipped with local ventilation and ducted to a fabric filter dust collector. 4. Drop points to woody biomass storage areas shall be designed to minimize the overall exposed drop height by utilizing telescoping discharge spouts to minimize the clearance between the spout outlet and the top of the storage pile. 5. Periodic equipment maintenance shall be performed to maintain conveyor systems and associated drop point integrity. Appropriate plant records shall be maintained on equipment maintenance performed. 6. Boiler fuel bins will be equipped with bin vent filters. 7. Daily observations of the conveyor systems and associated drop point integrity will be conducted to identify any equipment abnormalities. 8. Plant personnel shall be trained on identification of warning signs for potential equipment malfunction. 9. Signs shall be posted identifying potential warning signs of equipment malfunction. 10. All major roadways at the plant shall be paved. 11. Excessive mud, dirt or similar debris shall be removed promptly from the paved roads. 12. Plant personnel shall be trained on what constitutes excessive dust on paved roads. 13. All paved roadways and gravel areas at the plant shall be wetted as necessary to minimize fugitive dust emissions.

Best Management Practice – Storage Pile Management
1. Woody biomass storage areas shall be managed and maintained to avoid excessive wind erosion. 2. A woody biomass storage area fugitive dust management plan shall be developed and maintained onsite. Plan shall identify warning signs and train plant personnel regarding conditions that could result in excessive fugitive dust formation. The plan shall be submitted to the compliance authority 90 days after the plant becomes operational. 3. Mechanical moving of woody biomass by front end loaders and other supporting equipment shall be minimized on high wind event days. Wetting of the biomass will be utilized when necessary to minimize fugitive dust emissions when the biomass is being manipulated by front end loaders and other supporting equipment. 4. Daily visual observations of the woody biomass storage areas shall be performed and if conditions are favorable for fugitive dust formation, procedures from the storage area fugitive dust plan shall be implemented.

DRAFT

Best Management Practice – Fire Prevention /Spontaneous Combustion Minimization
1. Plant personnel will contact the City of Gainesville Fire Department to develop a Fire Management Plan (FMP). The FMP shall be maintained on site. 2. The FMP will include a requirement to train onsite personnel to handle incipient fires and training on the identification of potential fire hazards. In addition, GREC will install and maintain equipment for plant personnel to handle incipient fires. The City of Gainesville Fire Department shall be invited to participate in onsite training. 3. Daily observations of the woody biomass storage areas shall be performed by plant personnel to identify potential fire hazards. Plant personnel shall be trained on identification of potential fire hazards. 4. Spontaneous combustion and odor problems will be minimized by rotation of the fuel in the live storage pile and in the manual pile. 5. Signs shall be posted at GREC, which identify potential fire hazards. 6. The stacker reclaimer being used shall maximize the removal of older material in order to minimize the stacking of newer material on top of older material. The automatic stacker/reclaimer will be divided into multiple zones that can be managed to allow simultaneous stacking and reclaiming so that the storage piles are managed on a first in first out basis. The manual pile will be managed by the fuel yard manager and be divided into zones. Each day fuel will be added to new zones and removed from the oldest zones. 7. Compaction of woody biomass materials in the storage areas shall be minimized.

Best Management Practice – Quality Assurance of Clean Woody Biomass
1. The feedstock for the BFB boiler will consist of clean woody biomass that will be processed principally off site and then sorted, screened, and sized as necessary on site and then placed in the storage areas or sent directly to the BFB boiler. 2. The permittee will contract for woody biomass that specifically meets the definition of woody biomass as identified in the permit. The woody biomass will consist of clean untreated wood or untreated wood products including clean untreated lumber, tree stumps (whole or chipped), tree limbs (whole or chipped) and slash. This also includes, but is not limited to, wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including but not limited to sawdust, sander dust, wood chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues. 3. The woody biomass feedstock will be delivered to the GREC facility in vehicles designed to prevent release. 4. For each shipment of woody biomass, the permittee shall record the date, quantity and a description of the material received. 5. The permittee shall inspect each shipment of woody biomass upon receipt for any material not specifically identified in this plan (see below). If the permittee identifies any such material, the material shall be rejected and/or marshaled in specified areas until proper disposal can be arranged. Rejected materials shall be moved off site in a logistically reasonable time period. 6. The permittee shall maintain records of rejected shipments and disposition thereof. Such records shall be made available to the Department upon request.

DRAFT

COMMON CONDITIONS

Unless otherwise specified in the permit, the following conditions apply to all emissions units and activities at the GREC facility.

EMISSIONS AND CONTROLS

1. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the permittee shall notify each Compliance Authority as soon as possible, but at least within one working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; steps being taken to correct the problem and prevent future recurrence; and, where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit or the regulations. [Rule 62-4.130, F.A.C.]
2. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rule 62-210.650, F.A.C.]
3. Excess Emissions Allowed: Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed 2 hours in any 24-hour period unless specifically authorized by the Department for longer duration. Pursuant to Rule 62-210.700(5), F.A.C., the permit subsection may specify more or less stringent requirements for periods of excess emissions. Rule 62-210-700(Excess Emissions), F.A.C., cannot vary or supersede any federal NSPS or NESHAP provision. [Rule 62-210.700(1), F.A.C.]
4. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. [Rule 62-210.700(4), F.A.C.]
5. Excess Emissions - Notification: In case of excess emissions resulting from malfunctions, the permittee shall notify the Compliance Authority in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department. [Rule 62-210.700(6), F.A.C.]
6. VOC or OS Emissions: No person shall store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds (VOC) or organic solvents (OS) without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department. [Rule 62-296.320(1), F.A.C.]
7. Objectionable Odor Prohibited: No person shall cause, suffer, allow or permit the discharge of air pollutants, which cause or contribute to an objectionable odor. An "objectionable odor" means any odor present in the outdoor atmosphere which by itself or in combination with other odors, is or may be harmful or injurious to human health or welfare, which unreasonably interferes with the comfortable use and enjoyment of life or property, or which creates a nuisance. [Rules 62-296.320(2) and 62-210.200(Definitions), F.A.C.]
8. General Visible Emissions: No person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity equal to or greater than 20% opacity. This regulation does not impose a specific testing requirement. [Rule 62-296.320(4)(b)1, F.A.C.]
9. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

DRAFT

RECORDS AND REPORTS

10. Records Retention: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least 5 years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. [Rule 62-213.440(1)(b)2, F.A.C.]

11. Emissions Computation and Reporting

    a. *Applicability*. This rule sets forth required methodologies to be used by the owner or operator of a facility for computing actual emissions, baseline actual emissions, and net emissions increase, as defined at Rule 62-210.200, F.A.C., and for computing emissions for purposes of the reporting requirements of subsection 62-210.370(3) and paragraph 62-212.300(1)(e), F.A.C., or of any permit condition that requires emissions be computed in accordance with this rule. This rule is not intended to establish methodologies for determining compliance with the emission limitations of any air permit.

    b. *Computation of Emissions*. For any of the purposes set forth in subsection 62-210.370(1), F.A.C., the owner or operator of a facility shall compute emissions in accordance with the requirements set forth in this subsection.

        (1) Basic Approach. The owner or operator shall employ, on a pollutant-specific basis, the most accurate of the approaches set forth below to compute the emissions of a pollutant from an emissions unit; provided, however, that nothing in this rule shall be construed to require installation and operation of any continuous emissions monitoring system (CEMS), continuous parameter monitoring system (CPMS), or predictive emissions monitoring system (PEMS) not otherwise required by rule or permit, nor shall anything in this rule be construed to require performance of any stack testing not otherwise required by rule or permit.

            (a) If the emissions unit is equipped with a CEMS meeting the requirements of paragraph 62-210.370(2)(b), F.A.C., the owner or operator shall use such CEMS to compute the emissions of the pollutant, unless the owner or operator demonstrates to the department that an alternative approach is more accurate because the CEMS represents still-emerging technology.

            (b) If a CEMS is not available or does not meet the requirements of paragraph 62-210.370(2)(b), F.A.C, but emissions of the pollutant can be computed pursuant to the mass balance methodology of paragraph 62-210.370(2)(c), F.A.C., the owner or operator shall use such methodology, unless the owner or operator demonstrates to the department that an alternative approach is more accurate.

            (c) If a CEMS is not available or does not meet the requirements of paragraph 62-210.370(2)(b), F.A.C., and emissions cannot be computed pursuant to the mass balance methodology, the owner or operator shall use an emission factor meeting the requirements of paragraph 62-210.370(2)(d), F.A.C., unless the owner or operator demonstrates to the department that an alternative approach is more accurate.

        (2) Continuous Emissions Monitoring System (CEMS).

            (a) An owner or operator may use a CEMS to compute emissions of a pollutant for purposes of this rule provided:

                1) The CEMS complies with the applicable certification and quality assurance requirements of 40 CFR Part 60, Appendices B and F, or, for an acid rain unit, the certification and quality assurance requirements of 40 CFR Part 75, all adopted by reference at Rule 62-204.800, F.A.C.; or

DRAFT

2) The owner or operator demonstrates that the CEMS otherwise represents the most accurate means of computing emissions for purposes of this rule.

(b) Stack gas volumetric flow rates used with the CEMS to compute emissions shall be obtained by the most accurate of the following methods as demonstrated by the owner or operator:

1) A calibrated flowmeter that records data on a continuous basis, if available; or

2) The average flow rate of all valid stack tests conducted during a five-year period encompassing the period over which the emissions are being computed, provided all stack tests used shall represent the same operational and physical configuration of the unit.

(c) The owner or operator may use CEMS data in combination with an appropriate f-factor, heat input data, and any other necessary parameters to compute emissions if such method is demonstrated by the owner or operator to be more accurate than using a stack gas volumetric flow rate as set forth at subparagraph 62-210.370(2)(b)2., F.A.C., above.

(3) Mass Balance Calculations.

(a) An owner or operator may use mass balance calculations to compute emissions of a pollutant for purposes of this rule provided the owner or operator:

1) Demonstrates a means of validating the content of the pollutant that is contained in or created by all materials or fuels used in or at the emissions unit; and

2) Assumes that the emissions unit emits all of the pollutant that is contained in or created by any material or fuel used in or at the emissions unit if it cannot otherwise be accounted for in the process or in the capture and destruction of the pollutant by the unit's air pollution control equipment.

(b) Where the vendor of a raw material or fuel which is used in or at the emissions unit publishes a range of pollutant content from such material or fuel, the owner or operator shall use the highest value of the range to compute the emissions, unless the owner or operator demonstrates using site-specific data that another content within the range is more accurate.

(c) In the case of an emissions unit using coatings or solvents, the owner or operator shall document, through purchase receipts, records and sales receipts, the beginning and ending VOC inventories, the amount of VOC purchased during the computational period, and the amount of VOC disposed of in the liquid phase during such period.

(4) Emission Factors.

(a) An owner or operator may use an emission factor to compute emissions of a pollutant for purposes of this rule provided the emission factor is based on site-specific data such as stack test data, where available, unless the owner or operator demonstrates to the department that an alternative emission factor is more accurate. An owner or operator using site-specific data to derive an emission factor, or set of factors, shall meet the following requirements.

1) If stack test data are used, the emission factor shall be based on the average emissions per unit of input, output, or gas volume, whichever is appropriate, of all valid stack tests conducted during at least a five-year period encompassing the period over which the emissions are being computed, provided all stack tests used shall represent the same operational and physical configuration of the unit.

2) Multiple emission factors shall be used as necessary to account for variations in emission rate associated with variations in the emissions unit's operating rate or operating conditions during the period over which emissions are computed.

DRAFT

3) The owner or operator shall compute emissions by multiplying the appropriate emission factor by the appropriate input, output or gas volume value for the period over which the emissions are computed. The owner or operator shall not compute emissions by converting an emission factor to pounds per hour and then multiplying by hours of operation, unless the owner or operator demonstrates that such computation is the most accurate method available.

(b) If site-specific data are not available to derive an emission factor, the owner or operator may use a published emission factor directly applicable to the process for which emissions are computed. If no directly-applicable emission factor is available, the owner or operator may use a factor based on a similar, but different, process.

(5) Accounting for Emissions During Periods of Missing Data from CEMS, PEMS, or CPMS. In computing the emissions of a pollutant, the owner or operator shall account for the emissions during periods of missing data from CEMS, PEMS, or CPMS using other site-specific data to generate a reasonable estimate of such emissions.

(6) Accounting for Emissions During Periods of Startup and Shutdown. In computing the emissions of a pollutant, the owner or operator shall account for the emissions during periods of startup and shutdown of the emissions unit.

(7) Fugitive Emissions. In computing the emissions of a pollutant from a facility or emissions unit, the owner or operator shall account for the fugitive emissions of the pollutant, to the extent quantifiable, associated with such facility or emissions unit.

(8) Recordkeeping. The owner or operator shall retain a copy of all records used to compute emissions pursuant to this rule for a period of five years from the date on which such emissions information is submitted to the department for any regulatory purpose.

c. Annual Operating Report for Air Pollutant Emitting Facility

(1) The Annual Operating Report for Air Pollutant Emitting Facility (DEP Form No. 62-210.900(5)) shall be completed each year for the following facilities:

(a) All Title V sources.

(b) All synthetic non-Title V sources.

(c) All facilities with the potential to emit ten (10) tons per year or more of volatile organic compounds or twenty-five (25) tons per year or more of nitrogen oxides and located in an ozone nonattainment area or ozone air quality maintenance area.

(d) All facilities for which an annual operating report is required by rule or permit.

(2) Notwithstanding paragraph 62-210.370(3)(a), F.A.C., no annual operating report shall be required for any facility operating under an air general permit.

(3) The annual operating report shall be submitted to the appropriate Department of Environmental Protection (DEP) division, district or DEP-approved local air pollution control program office by April 1 of the following year.

(4) Beginning with 2007 annual emissions, emissions shall be computed in accordance with the provisions of subsection 62-210.370(2), F.A.C., for purposes of the annual operating report.

[Rule 62-210.370, F.A.C.]

DRAFT

CONTINUOUS EMISSIONS MONITORING SYSTEM (CEMS) REQUIREMENTS

CEMS OPERATION PLAN

1. CEMS Operation Plan: The owner or operator shall create and implement a facility-wide plan for the proper installation, calibration, maintenance and operation of each CEMS required by this permit. The owner or operator shall submit the CEMS Operation Plan to the Bureau of Air Monitoring and Mobile Sources for approval at least 60 days prior to CEMS installation. The CEMS Operation Plan shall become effective 60 days after submittal or upon its approval. If the CEMS Operation Plan is not approved, the owner or operator shall submit a new or revised plan for approval.

{Permitting Note: The Department maintains both guidelines for developing a CEMS Operation Plan and example language that can be used as the basis for the facility-wide plan required by this permit. Contact the Emissions Monitoring Section of the Bureau of Air Monitoring and Mobile Sources at (850)488-0114.}

INSTALLATION, PERFORMANCE SPECIFICATIONS AND QUALITY ASSURANCE

2. Timelines:

   a. *New and Existing Emission Units.* For new emission units, the owner or operator shall install each CEMS required by this permit prior to initial startup of the unit. The owner or operator shall conduct the appropriate performance specification for each CEMS within 90 operating days of achieving permitted capacity as defined in Rule 62-297.310(2), F.A.C., but no later than 180 calendar days after initial startup.

3. Installation: All CEMS shall be installed such that representative measurements of emissions or process parameters from the facility are obtained. The owner or operator shall locate the CEMS by following the procedures contained in the applicable performance specification of 40 CFR part 60, Appendix B.

4. Span Values and Dual Range Monitors: The owner or operator shall set appropriate span values for the CEMS. The owner or operator shall install dual range monitors if required by and in accordance with the CEMS Operation Plan.

5. Continuous Flow Monitor: For compliance with mass emission rate standards, the owner or operator shall install a continuous flow monitor to determine the stack exhaust flow rate. The flow monitor shall be certified pursuant to 40 CFR part 60, Appendix B, Performance Specification 6.

6. Diluent Monitor: If it is necessary to correct the CEMS output to the oxygen concentrations specified in this permit's emission standards, the owner or operator shall either install an oxygen monitor or install a CO_2 monitor and use an appropriate F-Factor computational approach.

7. Moisture Correction: If necessary, the owner or operator shall determine the moisture content of the exhaust gas and develop an algorithm to enable correction of the monitoring results to a dry basis (0% moisture).

{Permitting Note: The CEMS Operation Plan will contain additional CEMS-specific details and procedures for installation.}

8. Performance Specifications: The owner or operator shall evaluate the acceptability of each CEMS by conducting the appropriate performance specification, as follows. CEMS determined to be unacceptable shall not be considered installed for purposes of meeting the timelines of this permit.

   a. *CO Monitors:* For CO monitors, the owner or operator shall conduct Performance Specification 4 or 4A of 40 CFR part 60, Appendix B

   b. *NO_X and SO_2 Monitors:* For NO_X and SO_2 monitors, the owner or operator shall conduct Performance Specification 2 of 40 CFR part 60, Appendix B.

   c. *HCl CEMS*: The HCl CEMS shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 15, EPA Method OTM 22 or alternative specifications approved by the Department. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the

DRAFT

Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the Compliance Authority.

d. *HF CEMS*: The HF CEMS shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 15, EPA Method OTM 22 or alternative specifications approved by the Department. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the Compliance Authority.

e. *COMS*: In accordance with 40 CFR 60.48b(a) the permittee shall install, calibrate, operate and maintain a continuous opacity monitor (COM) to continuously monitor and record opacity from the steam generating unit. The COMS shall be certified pursuant to 40 CFR 60 Appendix B, Performance Specification 1.

9. Quality Assurance: The owner or operator shall follow the quality assurance procedures of 40 CFR part 60, Appendix F.

a. *CO Monitors:* The required relative accuracy test audit (RATA) tests shall be performed using EPA Method 10 in Appendix A of 40 CFR part 60 and shall be based on a continuous sampling train.

b. *NO_X Monitors:* The required RATA tests shall be performed using EPA Method 7E in Appendix A of 40 CFR part 60. NO_X shall be expressed "as NO_2."

c. *SO_2 Monitors:* The required RATA tests shall be performed using EPA Method 6C in Appendix A of 40 CFR part 60.

d. *HCl CEMS*: The HCl CEMS shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 15, EPA Method OTM 22 or alternative specifications approved by the Department. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, EPA Method OTM 23 or alternative procedures approved by the Department.
A Data Assessment Report shall be made each calendar quarter and reported semiannually to the Compliance Authority. The RATA tests required for the HCl monitor shall be performed using EPA Method 26 or 26A as detailed in Appendix A of 40 CFR 60 or by Method 320 as detailed in Appendix A of 40 CFR 63. The HCl monitor span values shall be set appropriately, considering the allowable methods of operation and corresponding emission standards. Approval of specific initial performance specifications and quality assurance and control (Q&A) procedures must be provided by the Department prior to installation and operation of the CEM system.

e. *HF CEMS*: The HF CEMS shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 15, EPA Method OTM 22 or alternative specifications approved by the Department. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, EPA Method OTM 23 or alternative procedures approved by the Department.
A Data Assessment Report shall be made each calendar quarter and reported semiannually to the Compliance Authority. The RATA tests required for the HF monitor shall be performed using EPA Method 26 or 26A as detailed in Appendix A of 40 CFR 60 or by Method 320 as detailed in Appendix A of 40 CFR 63. The HF monitor span values shall be set appropriately, considering the allowable methods of operation and corresponding emission standards. Approval of specific initial performance specifications and quality assurance and control (Q&A) procedures must be provided by the Department prior to installation and operation of the CEM system.

10. Substituting RATA Tests for Compliance Tests: Data collected during CEMS quality assurance RATA tests can substitute for annual stack tests, and vice versa, at the option of the owner or operator, provided the owner or operator indicates this intent in the submitted test protocol and follows the procedures outlined in the CEMS Operation Plan.

DRAFT

CALCULATION APPROACH

11. CEMS Used for Compliance: Once adherence to the applicable performance specification for each CEMS is demonstrated, the owner or operator shall use the CEMS to demonstrate compliance with the applicable emission standards as specified by this permit.

12. CEMS Data: Each CEMS shall monitor and record emissions during all periods of operation and whenever emissions are being generated, including during episodes of startups, shutdowns, and malfunctions. All data shall be used, except for invalid measurements taken during monitor system breakdowns, repairs, calibration checks, zero adjustments and span adjustments, and except for allowable data exclusions as per Condition 20 of this appendix.

13. Operating Hours and Operating Days: For purposes of this appendix, the following definitions shall apply. An hour is the 60-minute period beginning at the top of each hour. Any hour during which an emissions unit is in operation for more than 15 minutes is an operating hour for that emission unit. A day is the 24-hour period from midnight to midnight. Unless otherwise specified by this permit, any day with at least one operating hour for an emissions unit is an operating day for that emission unit.

14. Valid Hourly Averages*:* Each CEMS shall be designed and operated to sample, analyze and record data evenly spaced over the hour at a minimum of one measurement per minute. All valid measurements collected during an hour shall be used to calculate a 1-hour block average that begins at the top of each hour.

    a. Hours that are not operating hours are not valid hours.

    b. For each operating hour, the 1-hour block average shall be computed from at least two data points separated by a minimum of 15 minutes. If less than two such data points are available, there is insufficient data, the 1-hour block average is not valid, and the hour is considered as "monitor unavailable."

15. Calculation Approaches: The owner or operator shall implement the calculation approach specified by this permit for each CEMS, as follows:

    a. *Block 24-hour average*. Compliance shall be determined for each block averaging period by calculating the arithmetic average of all valid hourly averages occurring within that block averaging period. (On the first day, hours 0 to 23 are the first 24-hour block; on the second day, hours 0 to 23 are the second 24-hour block; etc.)

    b. *Rolling 30-day Average*: Compliance shall be determined after each operating day by calculating the arithmetic average of all the valid hourly averages from that operating day and the prior 29 operating days.

    c. *Rolling12-month average, rolled monthly:* Compliance shall be determined after each operating month by calculating the arithmetic average of all the valid hourly averages from that operating month and the prior x-1 operating months.

MONITOR AVAILABILITY

16. Monitor Availability: The quarterly excess emissions report shall identify monitor availability for each quarter in which the unit operated. Monitor availability for the CEMS shall be 95% or greater in any calendar quarter in which the unit operated for more than 760 hours. In the event the applicable availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving the required availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit.

DRAFT

EXCESS EMISSIONS

17. Definitions:

    a. *Startup* is defined as the commencement of operation of any emissions unit which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which result in excess emissions.

    b. *Shutdown* means the cessation of the operation of an emissions unit for any purpose.

    c. *Malfunction* means any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner.

18. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited.

19. Data Exclusion Procedures for SIP Compliance: As per the procedures in this condition, limited amounts of CEMS emissions data may be excluded from the corresponding compliance demonstration, provided that best operational practices to minimize emissions are adhered to and the duration of data excluded is minimized. The data exclusion procedures of this condition apply only to SIP-based emission limits.

    a. *Excess Emissions Allowed.* Data in excess of the applicable emission standard may be excluded from compliance calculations if the data are collected during periods of permitted excess emissions (for example, during startup, shutdown or malfunction). The maximum duration of excluded data is 2 hours in any 24-hour period, unless some other duration is specified by this permit.

    b. *Excess Emissions Prohibited.* For the CEMS on the BFB boiler stack at the GREC facility, excess emissions of NO_X and SO_2 based on 24-hour block averages during periods of startup, shutdown and malfunction cannot be excluded. This is to ensure that compliance with these emission limits. The NSPS, Subpart Da emissions limits for PM and NO_X do not apply during periods of startup, shutdown and malfunction. The NSPS, Subpart Da emissions limit for SO_2 do apply during periods of startup, shutdown and malfunction, but is excluded during emergency conditions.

    c. *Limited Data Exclusion.* If the compliance calculation using all valid CEMS emission data, as defined in Condition 12 of this appendix, indicates that the emission unit is in compliance, then no CEMS data shall be excluded from the compliance demonstration.

    d. *Event Driven Exclusion.* The underlying event (for example, the startup, shutdown or malfunction event) must precede the data exclusion. If there is no underlying event, then no data may be excluded. Only data collected during the event may be excluded.

    e. *Reporting Excluded Data.* The data exclusion procedures of this condition are not necessarily the same procedures used for excess emissions as defined by federal rules. Quarterly or semi-annual reports required by this permit shall indicate not only the duration of data excluded from SIP compliance calculations but also the number of excess emissions as defined by federal rules.

20. Notification Requirements: The owner or operator shall notify the Compliance Authority within one working day of discovering any emissions that demonstrate noncompliance for a given averaging period. Within one working day of occurrence, the owner or operator shall notify the Compliance Authority of any malfunction resulting in the exclusion of CEMS data. For malfunctions, notification is sufficient for the owner or operator to exclude CEMS data.

DRAFT

ANNUAL EMISSIONS

21. CEMS Used for Calculating Annual Emissions: All valid data, as defined in Condition 12 of this appendix, shall be used when calculating annual emissions.

    a. Annual emissions shall include data collected during startup, shutdown and malfunction periods.

    b. Annual emissions shall include data collected during periods when the emission unit is not operating but emissions are being generated (for example, when firing fuel to warm up a process for some period of time prior to the emission unit's startup).

    c. Annual emissions shall not include data from periods of time where the monitor was functioning properly but was unable to collect data while conducting a mandated quality assurance/quality control activity such as calibration error tests, RATA, calibration gas audit or RAA. These periods of time shall be considered missing data for purposes of calculating annual emissions.

    d. Annual emissions shall not include data from periods of time when emissions are in excess of the calibrated span of the CEMS. These periods of time shall be considered missing data for purposes of calculating annual emissions.

22. Accounting for Missing Data: All valid measurements collected during each hour shall be used to calculate a 1-hour block average. For each hour, the 1-hour block average shall be computed from at least two data points separated by a minimum of 15 minutes. If less than two such data points are available, the owner or operator shall account for emissions during that hour using site-specific data to generate a reasonable estimate of the 1-hour block average.

23. Emissions Calculation: Hourly emissions shall be calculated for each hour as the product of the 1-hour block average and the duration of pollutant emissions during that hour. Annual emissions shall be calculated as the sum of all hourly emissions occurring during the year.

DRAFT

CITATION FORMATS

The following illustrate the formats used in the permit to identify applicable requirements from permits and regulations.

Old Permit Numbers

Example: Permit No. AC50-123456 or Permit No. AO50-123456

Where: "AC" identifies the permit as an Air Construction Permit
"AO" identifies the permit as an Air Operation Permit
"123456" identifies the specific permit project number

New Permit Numbers

Example: Permit Nos. 099-2222-001-AC, 099-2222-001-AF, 099-2222-001-AO, or 099-2222-001-AV

Where: "099" represents the specific county ID number in which the project is located

"2222" represents the specific facility ID number for that county

"001"identifies the specific permit project number

"AC" identifies the permit as an air construction permit

"AF" identifies the permit as a minor source federally enforceable state operation permit

"AO" identifies the permit as a minor source air operation permit

"AV" identifies the permit as a major Title V air operation permit

PSD Permit Numbers

Example: Permit No. PSD-FL-317

Where: "PSD" means issued pursuant to the preconstruction review requirements of the Prevention of Significant Deterioration of Air Quality

"FL" means that the permit was issued by the State of Florida

"317" identifies the specific permit project number

Florida Administrative Code (F.A.C.)

Example: [Rule 62-213.205, F.A.C.]

Means: Title 62, Chapter 213, Rule 205 of the Florida Administrative Code

Code of Federal Regulations (CFR)

Example: [40 CRF 60.7]

Means: Title 40, Part 60, Section 7

DRAFT

GLOSSARY OF COMMON TERMS

° F: degrees Fahrenheit

acfm: actual cubic feet per minute

ARMS: Air Resource Management System (Department's database)

BACT: best available control technology

Btu: British thermal units

CAM: compliance assurance monitoring

CEMS: continuous emissions monitoring system

cfm: cubic feet per minute

CFR: Code of Federal Regulations

CO: carbon monoxide

COMS: continuous opacity monitoring system

DEP: Department of Environmental Protection

Department: Department of Environmental Protection

dscfm: dry standard cubic feet per minute

EPA: Environmental Protection Agency

ESP: electrostatic precipitator (control system for reducing particulate matter)

EU: emissions unit

F.A.C.: Florida Administrative Code

F.D.: forced draft

F.S.: Florida Statutes

FGR: flue gas recirculation

F: fluoride

ft^2: square feet

ft^3: cubic feet

gpm: gallons per minute

gr: grains

HAP: hazardous air pollutant

Hg: mercury

I.D.: induced draft

ID: identification

kPa: kilopascals

lb: pound

MACT: maximum achievable technology

MMBtu: million British thermal units

MSDS: material safety data sheets

MW: megawatt

NESHAP: National Emissions Standards for Hazardous Air Pollutants

NO_X: nitrogen oxides

NSPS: New Source Performance Standards

O&M: operation and maintenance

O_2: oxygen

Pb: lead

PM: particulate matter

PM_{10}: particulate matter with a mean aerodynamic diameter of 10 microns or less

PSD: prevention of signifi9cant deterioration

psi: pounds per square inch

PTE: potential to emit

RATA: relative accuracy test audit

SAM: sulfuric acid mist

scf: standard cubic feet

scfm: standard cubic feet per minute

SIC: standard industrial classification code

SNCR: selective non-catalytic reduction (control system used for reducing emissions of nitrogen oxides)

SO_2: sulfur dioxide

TPH: tons per hour

TPY: tons per year

UTM: Universal Transverse Mercator coordinate system

VE: visible emissions

VOC: volatile organic compounds

DRAFT

Unless otherwise specified in the permit, the following testing requirements apply to all emissions units at the GREC facility.

COMPLIANCE TESTING REQUIREMENTS

1. Operating Rate During Testing: Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the maximum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test rate until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. [Rule 62-297.310(2), F.A.C.]

2. Applicable Test Procedures - Opacity Compliance Tests: When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:

   a. For batch, cyclical processes, or other operations which are normally completed within less than the minimum observation period and do not recur within that time, the period of observation shall be equal to the duration of the batch cycle or operation completion time.

   b. The observation period for special opacity tests that are conducted to provide data to establish a surrogate standard pursuant to Rule 62-297.310(5)(k), F.A.C., Waiver of Compliance Test Requirements, shall be established as necessary to properly establish the relationship between a proposed surrogate standard and an existing mass emission limiting standard.

   c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.

   [Rule 62-297.310(4), F.A.C.]

3. Determination of Process Variables

   a. *Required Equipment*. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.

   b. *Accuracy of Equipment*. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.

   [Rule 62-297.310(5), F.A.C.]

4. Frequency of Compliance Tests: The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

   a. *General Compliance Testing*.

1. The owner or operator of a new or modified emissions unit that is subject to an emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining an operation permit for such emissions unit.
2. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to sub-subparagraph 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:
   (a) Did not operate; or
   (b) In the case of a fuel burning emissions unit, burned liquid and/or solid fuel for a total of no more than 400 hours,
3. During each federal fiscal year (October 1 – September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for visible emissions, if there is an applicable standard.
4. The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

b. *Special Compliance Tests*. When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department.

[Rule 62-297.310(7), F.A.C.]

RECORDS AND REPORTS

5. Test Reports: The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test. The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed. The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report shall provide the following information.
   a. The type, location, and designation of the emissions unit tested.
   b. The facility at which the emissions unit is located.
   c. The owner or operator of the emissions unit.
   d. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
   e. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
   f. The date, starting time and end time of the observation.
   g. The test procedures used.

DRAFT

h. The names of individuals who furnished the process variable data, conducted the test, and prepared the report.

i. The applicable emission standard and the resulting maximum allowable emission rate for the emissions unit plus the test result in the same form and unit of measure.

j. A certification that to the knowledge of the owner or his authorized agent, all data submitted are true and correct. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

[Rule 62-297.310(8), F.A.C.]

DRAFT

NSPS, 40 CFR 60, SUBPART Da – STANDARDS OF PERFORMANCE FOR ELECTRIC UTILITY STEAM GENERATING UNITS FOR WHICH CONSTRUCTION IS COMMENCED AFTER SEPTEMBER 18, 1978

Source: 72 FR 32722, June 13, 2007, unless otherwise noted.

§ 60.40Da Applicability and designation of affected facility.

(a) Except as specified in paragraph (e) of this section, the affected facility to which this subpart applies is each electric utility steam generating unit:

(1) That is capable of combusting more than 73 megawatts (MW) (250 million British thermal units per hour (MMBtu/hr)) heat input of fossil fuel (either alone or in combination with any other fuel); and

(2) For which construction, modification, or reconstruction is commenced after September 18, 1978.

(b) An IGCC electric utility steam generating unit (both the stationary combustion turbine and any associated duct burners) is subject to this part and is not subject to subpart GG or KKKK of this part if both of the conditions specified in paragraphs (b)(1) and (2) of this section are met.

(1) The IGCC electric utility steam generating unit is capable of combusting more than 73 MW (250 MMBtu/hr) heat input of fossil fuel (either alone or in combination with any other fuel); and

(2) The IGCC electric utility steam generating unit commenced construction, modification, or reconstruction after February 28, 2005.

(c) Any change to an existing fossil-fuel-fired steam generating unit to accommodate the use of combustible materials, other than fossil fuels, shall not bring that unit under the applicability of this subpart.

(d) Any change to an existing steam generating unit originally designed to fire gaseous or liquid fossil fuels, to accommodate the use of any other fuel (fossil or non-fossil) shall not bring that unit under the applicability of this subpart.

(e) Applicability of the requirement of this subpart to an electric utility combined cycle gas turbine other than an IGCC electric utility steam generating unit is as specified in paragraphs (e)(1) and (2) of this section.

(1) Heat recovery steam generators used with duct burners and associated with an electric utility combined cycle gas turbine that are capable of combusting more than 73 MW (250 MMBtu/hr) heat input of fossil fuel are subject to this subpart except in cases when the heat recovery steam generator meets the applicability requirements and is subject to subpart KKKK of this part.

(2) For heat recovery steam generators use with duct burners subject to this subpart, only emissions resulting from the combustion of fuels in the steam generating unit (i.e. duct burners) are subject to the standards under this subpart. (The emissions resulting from the combustion of fuels in the stationary combustion turbine engine are subject to subpart GG or KKK, as applicable, of this part).

[72 FR 32722, June 13, 2007, as amended at 74 FR 5078, Jan. 28, 2009]

§ 60.41Da Definitions.

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

Anthracite means coal that is classified as anthracite according to the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17).

Available purchase power means the lesser of the following:

(a) The sum of available system capacity in all neighboring companies.

(b) The sum of the rated capacities of the power interconnection devices between the principal company and all neighboring companies, minus the sum of the electric power load on these interconnections.

DRAFT

(c) The rated capacity of the power transmission lines between the power interconnection devices and the electric generating units (the unit in the principal company that has the malfunctioning flue gas desulfurization system and the unit(s) in the neighboring company supplying replacement electrical power) less the electric power load on these transmission lines.

Available system capacity means the capacity determined by subtracting the system load and the system emergency reserves from the net system capacity.

Biomass means plant materials and animal waste.

Bituminous coal means coal that is classified as bituminous according to the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17).

Boiler operating day for units constructed, reconstructed, or modified on or before February 28, 2005, means a 24-hour period during which fossil fuel is combusted in a steam-generating unit for the entire 24 hours. For units constructed, reconstructed, or modified after February 28, 2005, *boiler operating day* means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the steam-generating unit. It is not necessary for fuel to be combusted the entire 24-hour period.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17) and coal refuse. Synthetic fuels derived from coal for the purpose of creating useful heat, including but not limited to solvent-refined coal, gasified coal (not meeting the definition of natural gas), coal-oil mixtures, and coal-water mixtures are included in this definition for the purposes of this subpart.

Coal-fired electric utility steam generating unit means an electric utility steam generating unit that burns coal, coal refuse, or a synthetic gas derived from coal either exclusively, in any combination together, or in any combination with other fuels in any amount.

Coal refuse means waste products of coal mining, physical coal cleaning, and coal preparation operations (*e.g.* culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material.

Cogeneration, also known as "combined heat and power," means a steam-generating unit that simultaneously produces both electric (or mechanical) and useful thermal energy from the same primary energy source.

Combined cycle gas turbine means a stationary turbine combustion system where heat from the turbine exhaust gases is recovered by a steam generating unit.

Dry flue gas desulfurization technology or *dry FGD* means a sulfur dioxide control system that is located downstream of the steam generating unit and removes sulfur oxides (SO_2) from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline reagent and water, whether introduced separately or as a premixed slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline slurries or solutions used in dry FGD technology include, but are not limited to, lime and sodium.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary gas turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a heat recovery steam generating unit.

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

DRAFT

Electric utility company means the largest interconnected organization, business, or governmental entity that generates electric power for sale (*e.g.* , a holding company with operating subsidiary companies).

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

Electrostatic precipitator or *ESP* means an add-on air pollution control device used to capture particulate matter (PM) by charging the particles using an electrostatic field, collecting the particles using a grounded collecting surface, and transporting the particles into a hopper.

Emergency condition means that period of time when:

(1) The electric generation output of an affected facility with a malfunctioning flue gas desulfurization system cannot be reduced or electrical output must be increased because:

(i) All available system capacity in the principal company interconnected with the affected facility is being operated, and

(ii) All available purchase power interconnected with the affected facility is being obtained, or

(2) The electric generation demand is being shifted as quickly as possible from an affected facility with a malfunctioning flue gas desulfurization system to one or more electrical generating units held in reserve by the principal company or by a neighboring company, or

(3) An affected facility with a malfunctioning flue gas desulfurization system becomes the only available unit to maintain a part or all of the principal company's system emergency reserves and the unit is operated in spinning reserve at the lowest practical electric generation load consistent with not causing significant physical damage to the unit. If the unit is operated at a higher load to meet load demand, an emergency condition would not exist unless the conditions under paragraph (1) of this definition apply.

Emission limitation means any emissions limit or operating limit.

Emission rate period means any calendar month included in a 12-month rolling average period.

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 51.24.

Fossil fuel means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

Gaseous fuel means any fuel derived from coal or petroleum that is present as a gas at standard conditions and includes, but is not limited to, refinery fuel gas, process gas, coke-oven gas, synthetic gas, and gasified coal.

Gross output means the gross useful work performed by the steam generated and, for an IGCC electric utility steam generating unit, the work performed by the stationary combustion turbines. For a unit generating only electricity, the gross useful work performed is the gross electrical output from the unit's turbine/generator sets. For a cogeneration unit, the gross useful work performed is the gross electrical or mechanical output plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (*i.e.* , steam delivered to an industrial process).

24-hour period means the period of time between 12:01 a.m. and 12:00 midnight.

DRAFT

Integrated gasification combined cycle electric utility steam generating unit or *IGCC electric utility steam generating unit* means an electric utility combined cycle gas turbine that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas. No solid fuel is directly burned in the unit during operation.

Interconnected means that two or more electric generating units are electrically tied together by a network of power transmission lines, and other power transmission equipment.

ISO conditions means a temperature of 288 Kelvin, a relative humidity of 60 percent, and a pressure of 101.3 kilopascals.

Lignite means coal that is classified as lignite A or B according to the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17).

Natural gas means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

(2) Liquid petroleum gas, as defined by the American Society of Testing and Materials in ASTM D1835 (incorporated by reference, see §60.17); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 34 and 43 megajoules (MJ) per dry standard cubic meter (910 and 1,150 Btu per dry standard cubic foot).

Neighboring company means any one of those electric utility companies with one or more electric power interconnections to the principal company and which have geographically adjoining service areas.

Net-electric output means the gross electric sales to the utility power distribution system minus purchased power on a calendar year basis.

Net system capacity means the sum of the net electric generating capability (not necessarily equal to rated capacity) of all electric generating equipment owned by an electric utility company (including steam generating units, internal combustion engines, gas turbines, nuclear units, hydroelectric units, and all other electric generating equipment) plus firm contractual purchases that are interconnected to the affected facility that has the malfunctioning flue gas desulfurization system. The electric generating capability of equipment under multiple ownership is prorated based on ownership unless the proportional entitlement to electric output is otherwise established by contractual arrangement.

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Petroleum means crude oil or a fuel derived from crude oil, including, but not limited to, distillate oil, and residual oil.

Potential combustion concentration means the theoretical emissions (nanograms per joule (ng/J), lb/MMBtu heat input) that would result from combustion of a fuel in an uncleaned state without emission control systems) and:

(1) For particulate matter (PM) is:

(i) 3,000 ng/J (7.0 lb/MMBtu) heat input for solid fuel; and

(ii) 73 ng/J (0.17 lb/MMBtu) heat input for liquid fuels.

(2) For sulfur dioxide (SO_2) is determined under §60.50Da(c).

(3) For nitrogen oxides (NO_X) is:

DRAFT

(i) 290 ng/J (0.67 lb/MMBtu) heat input for gaseous fuels;

(ii) 310 ng/J (0.72 lb/MMBtu) heat input for liquid fuels; and

(iii) 990 ng/J (2.30 lb/MMBtu) heat input for solid fuels.

Potential electrical output capacity means 33 percent of the maximum design heat input capacity of the steam generating unit, divided by 3,413 Btu/KWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 hr/yr (*e.g.* , a steam generating unit with a 100 MW (340 MMBtu/hr) fossil-fuel heat input capacity would have a 289,080 MWh 12 month potential electrical output capacity). For electric utility combined cycle gas turbines the potential electrical output capacity is determined on the basis of the fossil-fuel firing capacity of the steam generator exclusive of the heat input and electrical power contribution by the gas turbine.

Principal company means the electric utility company or companies which own the affected facility.

Resource recovery unit means a facility that combusts more than 75 percent non-fossil fuel on a quarterly (calendar) heat input basis.

Responsible official means responsible official as defined in 40 CFR 70.2.

Solid-derived fuel means any solid, liquid, or gaseous fuel derived from solid fuel for the purpose of creating useful heat and includes, but is not limited to, solvent refined coal, liquified coal, synthetic gas, gasified coal, gasified petroleum coke, gasified biomass, and gasified tire derived fuel.

Spare flue gas desulfurization system module means a separate system of SO_2emission control equipment capable of treating an amount of flue gas equal to the total amount of flue gas generated by an affected facility when operated at maximum capacity divided by the total number of nonspare flue gas desulfurization modules in the system.

Spinning reserve means the sum of the unutilized net generating capability of all units of the electric utility company that are synchronized to the power distribution system and that are capable of immediately accepting additional load. The electric generating capability of equipment under multiple ownership is prorated based on ownership unless the proportional entitlement to electric output is otherwise established by contractual arrangement.

Steam generating unit means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with combined cycle gas turbines; nuclear steam generators are not included).

Subbituminous coal means coal that is classified as subbituminous A, B, or C according to the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17).

System emergency reserves means an amount of electric generating capacity equivalent to the rated capacity of the single largest electric generating unit in the electric utility company (including steam generating units, internal combustion engines, gas turbines, nuclear units, hydroelectric units, and all other electric generating equipment) which is interconnected with the affected facility that has the malfunctioning flue gas desulfurization system. The electric generating capability of equipment under multiple ownership is prorated based on ownership unless the proportional entitlement to electric output is otherwise established by contractual arrangement.

System load means the entire electric demand of an electric utility company's service area interconnected with the affected facility that has the malfunctioning flue gas desulfurization system plus firm contractual sales to other electric utility companies. Sales to other electric utility companies (*e.g.* , emergency power) not on a firm contractual basis may also be included in the system load when no available system capacity exists in the electric utility company to which the power is supplied for sale.

DRAFT

Wet flue gas desulfurization technology or *wet FGD* means a SO_2control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a liquid material. This definition applies to devices where the aqueous liquid material product of this contact is subsequently converted to other forms. Alkaline reagents used in wet FGD technology include, but are not limited to, lime, limestone, and sodium.

[72 FR 32722, June 13, 2007, as amended at 74 FR 5079, Jan. 28, 2009]

§ 60.42Da Standard for particulate matter (PM).

(a) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced before or on February 28, 2005, any gases that contain PM in excess of:

(1) 13 ng/J (0.03 lb/MMBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel;

(2) 1 percent of the potential combustion concentration (99 percent reduction) when combusting solid fuel; and

(3) 30 percent of potential combustion concentration (70 percent reduction) when combusting liquid fuel.

(b) On and after the date the initial PM performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. Owners and operators of an affected facility that elect to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart are exempt from the opacity standard specified in this paragraph b.

(c) Except as provided in paragraph (d) of this section, on and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of either:

(1) 18 ng/J (0.14 lb/MWh) gross energy output; or

(2) 6.4 ng/J (0.015 lb/MMBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel.

(d) As an alternative to meeting the requirements of paragraph (c) of this section, the owner or operator of an affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility shall cause to be discharged into the atmosphere from that affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, any gases that contain PM in excess of:

(1) 13 ng/J (0.03 lb/MMBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel, and

(2) 0.1 percent of the combustion concentration determined according to the procedure in §60.48Da(o)(5) (99.9 percent reduction) for an affected facility for which construction or reconstruction commenced after February 28, 2005 when combusting solid, liquid, or gaseous fuel, or

DRAFT

(3) 0.2 percent of the combustion concentration determined according to the procedure in §60.48Da(o)(5) (99.8 percent reduction) for an affected facility for which modification commenced after February 28, 2005 when combusting solid, liquid, or gaseous fuel.

[72 FR 32722, June 13, 2007, as amended at 74 FR 5079, Jan. 28, 2009]

§ 60.43Da Standard for sulfur dioxide (SO_2).

(a) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts solid fuel or solid-derived fuel and for which construction, reconstruction, or modification commenced before or on February 28, 2005, except as provided under paragraphs (c), (d), (f) or (h) of this section, any gases that contain SO_2in excess of:

(1) 520 ng/J (1.20 lb/MMBtu) heat input and 10 percent of the potential combustion concentration (90 percent reduction); or

(2) 30 percent of the potential combustion concentration (70 percent reduction), when emissions are less than 260 ng/J (0.60 lb/MMBtu) heat input.

(b) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts liquid or gaseous fuels (except for liquid or gaseous fuels derived from solid fuels and as provided under paragraphs (e) or (h) of this section) and for which construction, reconstruction, or modification commenced before or on February 28, 2005, any gases that contain SO_2in excess of:

(1) 340 ng/J (0.80 lb/MMBtu) heat input and 10 percent of the potential combustion concentration (90 percent reduction); or

(2) 100 percent of the potential combustion concentration (zero percent reduction) when emissions are less than 86 ng/J (0.20 lb/MMBtu) heat input.

(c) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts solid solvent refined coal (SRC–I) any gases that contain SO_2in excess of 520 ng/J (1.20 lb/MMBtu) heat input and 15 percent of the potential combustion concentration (85 percent reduction) except as provided under paragraph (f) of this section; compliance with the emission limitation is determined on a 30-day rolling average basis and compliance with the percent reduction requirement is determined on a 24-hour basis.

(d) Sulfur dioxide emissions are limited to 520 ng/J (1.20 lb/MMBtu) heat input from any affected facility which:

(1) Combusts 100 percent anthracite;

(2) Is classified as a resource recovery unit; or

(3) Is located in a noncontinental area and combusts solid fuel or solid-derived fuel.

(e) Sulfur dioxide emissions are limited to 340 ng/J (0.80 lb/MMBtu) heat input from any affected facility which is located in a noncontinental area and combusts liquid or gaseous fuels (excluding solid-derived fuels).

(f) The emission reduction requirements under this section do not apply to any affected facility that is operated under an SO_2commercial demonstration permit issued by the Administrator in accordance with the provisions of §60.47Da.

DRAFT

(g) Compliance with the emission limitation and percent reduction requirements under this section are both determined on a 30-day rolling average basis except as provided under paragraph (c) of this section.

(h) When different fuels are combusted simultaneously, the applicable standard is determined by proration using the following formula:

(1) If emissions of $SO_2$to the atmosphere are greater than 260 ng/J (0.60 lb/MMBtu) heat input

$$E_s = \frac{(340x + 520y)}{100} \quad \text{and} \quad \%P_s = 10$$

(2) If emissions of $SO_2$to the atmosphere are equal to or less than 260 ng/J (0.60 lb/MMBtu) heat input:

$$E_s = \frac{(340x + 520y)}{100} \quad \text{and} \quad \%P_s = \frac{(10x + 30y)}{100}$$

Where:

E_s= Prorated SO_2emission limit (ng/J heat input);

$\%P_s$= Percentage of potential SO_2emission allowed;

x = Percentage of total heat input derived from the combustion of liquid or gaseous fuels (excluding solid-derived fuels); and

y = Percentage of total heat input derived from the combustion of solid fuel (including solid-derived fuels).

(i) Except as provided in paragraphs (j) and (k) of this section, on and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification commenced after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility, any gases that contain SO_2in excess of the applicable emission limitation specified in paragraphs (i)(1) through (3) of this section.

(1) For an affected facility for which construction commenced after February 28, 2005, any gases that contain SO_2in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis; or

(ii) 5 percent of the potential combustion concentration (95 percent reduction) on a 30-day rolling average basis.

(2) For an affected facility for which reconstruction commenced after February 28, 2005, any gases that contain SO_2in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis;

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis; or

(iii) 5 percent of the potential combustion concentration (95 percent reduction) on a 30-day rolling average basis.

(3) For an affected facility for which modification commenced after February 28, 2005, any gases that contain SO_2in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis;

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis; or

(iii) 10 percent of the potential combustion concentration (90 percent reduction) on a 30-day rolling average basis.

DRAFT

(j) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification commenced after February 28, 2005, and that burns 75 percent or more (by heat input) coal refuse on a 12-month rolling average basis, shall caused to be discharged into the atmosphere from that affected facility any gases that contain SO_2in excess of the applicable emission limitation specified in paragraphs (j)(1) through (3) of this section.

(1) For an affected facility for which construction commenced after February 28, 2005, any gases that contain SO_2in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis; or

(ii) 6 percent of the potential combustion concentration (94 percent reduction) on a 30-day rolling average basis.

(2) For an affected facility for which reconstruction commenced after February 28, 2005, any gases that contain SO_2in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis;

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis; or

(iii) 6 percent of the potential combustion concentration (94 percent reduction) on a 30-day rolling average basis.

(3) For an affected facility for which modification commenced after February 28, 2005, any gases that contain SO_2in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis;

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis; or

(iii) 10 percent of the potential combustion concentration (90 percent reduction) on a 30-day rolling average basis.

(k) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility located in a noncontinental area that commenced construction, reconstruction, or modification commenced after February 28, 2005, shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2in excess of the applicable emission limitation specified in paragraphs (k)(1) and (2) of this section.

(1) For an affected facility that burns solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain SO_2in excess of 520 ng/J (1.2 lb/MMBtu) heat input on a 30-day rolling average basis.

(2) For an affected facility that burns other than solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain SO_2in excess of if the affected facility or 230 ng/J (0.54 lb/MMBtu) heat input on a 30-day rolling average basis.

§ 60.44Da Standard for nitrogen oxides (NOX).

(a) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility, except as provided under paragraphs (b), (d), (e), and (f) of this section, any gases that contain NO_X(expressed as NO_2) in excess of the following emission limits, based on a 30-day rolling average basis, except as provided under §60.48Da(j)(1):

DRAFT

(1) NO_X emission limits.

Fuel type	Emission limit for heat input	
	ng/J	lb/MMBtu
Gaseous fuels:		
Coal-derived fuels	210	0.50
All other fuels	86	0.20
Liquid fuels:		
Coal-derived fuels	210	0.50
Shale oil	210	0.50
All other fuels	130	0.30
Solid fuels:		
Coal-derived fuels	210	0.50
Any fuel containing more than 25%, by weight, coal refuse	(1)	(1)
Any fuel containing more than 25%, by weight, lignite if the lignite is mined in North Dakota, South Dakota, or Montana, and is combusted in a slag tap furnace[2]	340	0.80
Any fuel containing more than 25%, by weight, lignite not subject to the 340 ng/J heat input emission limit[2]	260	0.60
Subbituminous coal	210	0.50
Bituminous coal	260	0.60
Anthracite coal	260	0.60
All other fuels	260	0.60

[1]Exempt from NO_X standards and NO_X monitoring requirements.

[2]Any fuel containing less than 25%, by weight, lignite is not prorated but its percentage is added to the percentage of the predominant fuel.

DRAFT

(2) NO_Xreduction requirement.

Fuel type	Percent reduction of potential combustion concentration
Gaseous fuels	25
Liquid fuels	30
Solid fuels	65

(b) The emission limitations under paragraph (a) of this section do not apply to any affected facility which is combusting coal-derived liquid fuel and is operating under a commercial demonstration permit issued by the Administrator in accordance with the provisions of §60.47Da.

(c) Except as provided under paragraphs (d), (e), and (f) of this section, when two or more fuels are combusted simultaneously, the applicable standard is determined by proration using the following formula:

$$E_n = \frac{(86w + 130x + 210y + 260z + 340v)}{100}$$

Where:

E_n= Applicable standard for $NO_X$when multiple fuels are combusted simultaneously (ng/J heat input);

w = Percentage of total heat input derived from the combustion of fuels subject to the 86 ng/J heat input standard;

x = Percentage of total heat input derived from the combustion of fuels subject to the 130 ng/J heat input standard;

y = Percentage of total heat input derived from the combustion of fuels subject to the 210 ng/J heat input standard;

z = Percentage of total heat input derived from the combustion of fuels subject to the 260 ng/J heat input standard; and

v = Percentage of total heat input delivered from the combustion of fuels subject to the 340 ng/J heat input standard.

(d)(1) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction after July 9, 1997, but before or on February 28, 2005 shall cause to be discharged into the atmosphere any gases that contain NO_X(expressed as NO_2) in excess of 200 ng/J (1.6 lb/MWh) gross energy output, based on a 30-day rolling average basis, except as provided under §60.48Da(k).

(2) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of affected facility for which reconstruction commenced after July 9, 1997, but before or on February 28, 2005 shall cause to be discharged into the atmosphere any gases that contain NO_X(expressed as NO_2) in excess of 65 ng/J (0.15 lb/MMBtu) heat input, based on a 30-day rolling average basis.

(e) Except for an IGCC electric utility steam generating unit meeting the requirements of paragraph (f) of this section, on and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced

DRAFT

construction, reconstruction, or modification after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X(expressed as NO_2) in excess of the applicable emission limitation specified in paragraphs (e)(1) through (3) of this section.

(1) For an affected facility for which construction commenced after February 28, 2005, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO_X(expressed as NO_2) in excess of 130 ng/J (1.0 lb/MWh) gross energy output on a 30-day rolling average basis, except as provided under §60.48Da(k).

(2) For an affected facility for which reconstruction commenced after February 28, 2005, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO_X(expressed as NO_2) in excess of either:

(i) 130 ng/J (1.0 lb/MWh) gross energy output on a 30-day rolling average basis; or

(ii) 47 ng/J (0.11 lb/MMBtu) heat input on a 30-day rolling average basis.

(3) For an affected facility for which modification commenced after February 28, 2005, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO_X(expressed as NO_2) in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis; or

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis.

(f) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, the owner or operator of an IGCC electric utility steam generating unit subject to the provisions of this subpart and for which construction, reconstruction, or modification commenced after February 28, 2005, shall meet the requirements specified in paragraphs (f)(1) through (3) of this section.

(1) Except as provided for in paragraphs (f)(2) and (3) of this section, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO_X(expressed as NO_2) in excess of 130 ng/J (1.0 lb/MWh) gross energy output on a 30-day rolling average basis.

(2) When burning liquid fuel exclusively or in combination with solid-derived fuel such that the liquid fuel contributes 50 percent or more of the total heat input to the combined cycle combustion turbine, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO_X(expressed as NO_2) in excess of 190 ng/J (1.5 lb/MWh) gross energy output on a 30-day rolling average basis.

(3) In cases when during a 30-day rolling average compliance period liquid fuel is burned in such a manner to meet the conditions in paragraph (f)(2) of this section for only a portion of the clock hours in the 30-day period, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO_X(expressed as NO_2) in excess of the computed weighted-average emissions limit based on the proportion of gross energy output (in MWh) generated during the compliance period for each of emissions limits in paragraphs (f)(1) and (2) of this section.

§ 60.45Da Standard for mercury (Hg).

(a) For each coal-fired electric utility steam generating unit other than an IGCC electric utility steam generating unit, on and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, modification, or reconstruction commenced after January 30, 2004, any gases that contain mercury (Hg) emissions in excess of each Hg emissions limit in paragraphs (a)(1) through (5) of this section that applies to you. The Hg emissions limits in paragraphs (a)(1) through (5) of this section are based on a 12-month rolling average basis using the procedures in §60.50Da(h).

DRAFT

(1) For each coal-fired electric utility steam generating unit that burns only bituminous coal, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of 20×10^{-6} pound per megawatt hour (lb/MWh) or 0.020 lb/gigawatt-hour (GWh) on an output basis. The International System of Units (SI) equivalent is 0.0025 ng/J.

(2) For each coal-fired electric utility steam generating unit that burns only subbituminous coal:

(i) If your unit is located in a county-level geographical area receiving greater than 25 inches per year (in/yr) mean annual precipitation, based on the most recent publicly available U.S. Department of Agriculture 30-year data, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of 66×10^{-6} lb/MWh or 0.066 lb/GWh on an output basis. The SI equivalent is 0.0083 ng/J.

(ii) If your unit is located in a county-level geographical area receiving less than or equal to 25 in/yr mean annual precipitation, based on the most recent publicly available U.S. Department of Agriculture 30-year data, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of 97×10^{-6} lb/MWh or 0.097 lb/GWh on an output basis. The SI equivalent is 0.0122 ng/J.

(3) For each coal-fired electric utility steam generating unit that burns only lignite, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of 175×10^{-6} lb/MWh or 0.175 lb/GWh on an output basis. The SI equivalent is 0.0221 ng/J.

(4) For each coal-burning electric utility steam generating unit that burns only coal refuse, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of 16×10^{-6} lb/MWh or 0.016 lb/GWh on an output basis. The SI equivalent is 0.0020 ng/J.

(5) For each coal-fired electric utility steam generating unit that burns a blend of coals from different coal ranks (*i.e.* , bituminous coal, subbituminous coal, lignite) or a blend of coal and coal refuse, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of the unit-specific Hg emissions limit established according to paragraph (a)(5)(i) or (ii) of this section, as applicable to the affected unit.

(i) If you operate a coal-fired electric utility steam generating unit that burns a blend of coals from different coal ranks or a blend of coal and coal refuse, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of the computed weighted Hg emissions limit based on the Btu, MWh, or MJ) contributed by each coal rank burned during the compliance period and its applicable Hg emissions limit in paragraphs (a)(1) through (4) of this section as determined using Equation 1 in this section. For each affected source, you must comply with the weighted Hg emissions limit calculated using Equation 1 in this section based on the total Hg emissions from the unit and the total Btu, MWh, or MJ contributed by all fuels burned during the compliance period.

$$EL_b = \frac{\sum_{i=1}^{n} EL_i (HH_i)}{\sum_{i=1}^{n} HH_i} \qquad \text{(Eq. 1)}$$

Where:

EL_b= Total allowable Hg in lb/MWh that can be emitted to the atmosphere from any affected source being averaged according to this paragraph.

EL_i= Hg emissions limit for the subcategory i (coal rank) that applies to affected source, lb/MWh;

HH_i= For each affected source, the Btu, MWh, or MJ contributed by the corresponding subcategory i (coal rank) burned during the compliance period; and

n = Number of subcategories (coal ranks) being averaged for an affected source.

(ii) If you operate a coal-fired electric utility steam generating unit that burns a blend of coals from different coal ranks or a blend of coal and coal refuse together with one or more non-regulated, supplementary fuels, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of the computed weighted Hg emission limit based on the Btu, MWh, or MJ contributed by each coal rank burned during the compliance period and its applicable Hg emissions limit in paragraphs (a)(1) through (4) of this section as determined using Equation 1 in this section. For each affected source. You must comply with the weighted Hg emissions limit calculated using Equation 1 in this section based on the total Hg emissions from the unit contributed by both regulated and nonregulated fuels burned during the compliance period and the total Btu, MWh, or MJ contributed by both regulated and nonregulated fuels burned during the compliance period.

(b) For each IGCC electric utility steam generating unit, on and after the date on which the initial performance test required to be conducted under §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, modification, or reconstruction commenced after January 30, 2004, any gases that contain Hg emissions in excess of 20×10^{-6} lb/MWh or 0.020 lb/GWh on an output basis. The SI equivalent is 0.0025 ng/J. This Hg emissions limit is based on a 12-month rolling average basis using the procedures in §60.50Da(h).

§ 60.46Da [Reserved]

§ 60.47Da Commercial demonstration permit.

(a) An owner or operator of an affected facility proposing to demonstrate an emerging technology may apply to the Administrator for a commercial demonstration permit. The Administrator will issue a commercial demonstration permit in accordance with paragraph (e) of this section. Commercial demonstration permits may be issued only by the Administrator, and this authority will not be delegated.

(b) An owner or operator of an affected facility that combusts solid solvent refined coal (SRC–I) and who is issued a commercial demonstration permit by the Administrator is not subject to the SO_2emission reduction requirements under §60.43Da(c) but must, as a minimum, reduce SO_2emissions to 20 percent of the potential combustion concentration (80 percent reduction) for each 24-hour period of steam generator operation and to less than 520 ng/J (1.20 lb/MMBtu) heat input on a 30-day rolling average basis.

(c) An owner or operator of a fluidized bed combustion electric utility steam generator (atmospheric or pressurized) who is issued a commercial demonstration permit by the Administrator is not subject to the SO_2emission reduction requirements under §60.43Da(a) but must, as a minimum, reduce SO_2emissions to 15 percent of the potential combustion concentration (85 percent reduction) on a 30-day rolling average basis and to less than 520 ng/J (1.20 lb/MMBtu) heat input on a 30-day rolling average basis.

(d) The owner or operator of an affected facility that combusts coal-derived liquid fuel and who is issued a commercial demonstration permit by the Administrator is not subject to the applicable NO_xemission limitation and percent reduction under §60.44Da(a) but must, as a minimum, reduce emissions to less than 300 ng/J (0.70 lb/MMBtu) heat input on a 30-day rolling average basis.

DRAFT

(e) Commercial demonstration permits may not exceed the following equivalent MW electrical generation capacity for any one technology category, and the total equivalent MW electrical generation capacity for all commercial demonstration plants may not exceed 15,000 MW.

Technology	**Pollutant**	**Equivalent electrical capacity (MW electrical output)**
Solid solvent refined coal (SCR I)	SO2	6,000–10,000
Fluidized bed combustion (atmospheric)	SO2	400–3,000
Fluidized bed combustion (pressurized)	SO2	400–1,200
Coal liquification	NOX	750–10,000
Total allowable for all technologies		15,000

§ 60.48Da Compliance provisions.

(a) Compliance with the PM emission limitation under §60.42Da(a)(1) constitutes compliance with the percent reduction requirements for PM under §60.42Da(a)(2) and (3).

(b) Compliance with the NO_Xemission limitation under §60.44Da(a)(1) constitutes compliance with the percent reduction requirements under §60.44Da(a)(2).

(c) The PM emission standards under §60.42Da, the NO_Xemission standards under §60.44Da, and the Hg emission standards under §60.45Da apply at all times except during periods of startup, shutdown, or malfunction.

(d) During emergency conditions in the principal company, an affected facility with a malfunctioning flue gas desulfurization system may be operated if SO_2emissions are minimized by:

(1) Operating all operable flue gas desulfurization system modules, and bringing back into operation any malfunctioned module as soon as repairs are completed,

(2) Bypassing flue gases around only those flue gas desulfurization system modules that have been taken out of operation because they were incapable of any SO_2emission reduction or which would have suffered significant physical damage if they had remained in operation, and

(3) Designing, constructing, and operating a spare flue gas desulfurization system module for an affected facility larger than 365 MW (1,250 MMBtu/hr) heat input (approximately 125 MW electrical output capacity). The Administrator may at his discretion require the owner or operator within 60 days of notification to demonstrate spare module capability. To demonstrate this capability, the owner or operator must demonstrate compliance with the appropriate requirements under paragraph under §60.43Da(a), (b), (d), (e), and (h) for any period of operation lasting from 24 hours to 30 days when:

(i) Any one flue gas desulfurization module is not operated,

(ii) The affected facility is operating at the maximum heat input rate,

(iii) The fuel fired during the 24-hour to 30-day period is representative of the type and average sulfur content of fuel used over a typical 30-day period, and

(iv) The owner or operator has given the Administrator at least 30 days notice of the date and period of time over which the demonstration will be performed.

DRAFT

(e) After the initial performance test required under §60.8, compliance with the SO_2emission limitations and percentage reduction requirements under §60.43Da and the NO_Xemission limitations under §60.44Da is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30 day average emission rate for both $SO_2$and $NO_X$and a new percent reduction for $SO_2$are calculated to show compliance with the standards.

(f) For the initial performance test required under §60.8, compliance with the SO_2emission limitations and percent reduction requirements under §60.43Da and the NO_Xemission limitation under §60.44Da is based on the average emission rates for SO_2, NO_X, and percent reduction for $SO_2$for the first 30 successive boiler operating days. The initial performance test is the only test in which at least 30 days prior notice is required unless otherwise specified by the Administrator. The initial performance test is to be scheduled so that the first boiler operating day of the 30 successive boiler operating days is completed within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility.

(g) The owner or operator of an affected facility subject to emission limitations in this subpart shall determine compliance as follows:

(1) Compliance with applicable 30-day rolling average $SO_2$and NO_Xemission limitations is determined by calculating the arithmetic average of all hourly emission rates for $SO_2$and $NO_X$for the 30 successive boiler operating days, except for data obtained during startup, shutdown, malfunction (NO_Xonly), or emergency conditions (SO_2only).

(2) Compliance with applicable SO_2percentage reduction requirements is determined based on the average inlet and outlet SO_2emission rates for the 30 successive boiler operating days.

(3) Compliance with applicable daily average PM emission limitations is determined by calculating the arithmetic average of all hourly emission rates for PM each boiler operating day, except for data obtained during startup, shutdown, and malfunction. Averages are only calculated for boiler operating days that have valid data for at least 18 hours of unit operation during which the standard applies. Instead, all of the valid hourly emission rates of the operating day(s) not meeting the minimum 18 hours valid data daily average requirement are averaged with all of the valid hourly emission rates of the next boiler operating day with 18 hours or more of valid PM CEMS data to determine compliance.

(h) If an owner or operator has not obtained the minimum quantity of emission data as required under §60.49Da of this subpart, compliance of the affected facility with the emission requirements under §§60.43Da and 60.44Da of this subpart for the day on which the 30-day period ends may be determined by the Administrator by following the applicable procedures in section 7 of Method 19 of appendix A of this part.

(i) *Compliance provisions for sources subject to §60.44Da(d)(1), (e)(1), (e)(2)(i), (e)(3)(i), or (f)* . The owner or operator of an affected facility subject to §60.44Da(d)(1), (e)(1), (e)(2)(i), (e)(3)(i), or (f) shall calculate NO_Xemissions as 1.194×10^{-7} lb/scf-ppm times the average hourly NO_Xoutput concentration in ppm (measured according to the provisions of §60.49Da(c)), times the average hourly flow rate (measured in scfh, according to the provisions of §60.49Da(l) or §60.49Da(m)), divided by the average hourly gross energy output (measured according to the provisions of §60.49Da(k)). Alternatively, for oil-fired and gas-fired units, NO_Xemissions may be calculated by multiplying the hourly NO_Xemission rate in lb/MMBtu (measured by the CEMS required under §§60.49Da(c) and (d)), by the hourly heat input rate (measured according to the provisions of §60.49Da(n)), and dividing the result by the average gross energy output (measured according to the provisions of §60.49Da(k)).

(j) *Compliance provisions for duct burners subject to §60.44Da(a)(1)* . To determine compliance with the emissions limits for NO_Xrequired by §60.44Da(a) for duct burners used in combined cycle systems, either of the procedures described in paragraph (j)(1) or (2) of this section may be used:

(1) The owner or operator of an affected duct burner shall conduct the performance test required under §60.8 using the appropriate methods in appendix A of this part. Compliance with the emissions limits under §60.44Da(a)(1) is determined on the average of three (nominal 1-hour) runs for the initial and subsequent performance tests. During the performance test, one sampling site shall be located in the exhaust of the turbine prior to the duct burner. A second sampling site shall be located at the outlet from the heat recovery steam generating unit. Measurements shall be taken at both sampling sites during the performance test; or

(2) The owner or operator of an affected duct burner may elect to determine compliance by using the CEMS specified under §60.49Da for measuring $NO_X$and oxygen (O_2) (or carbon dioxide (CO_2)) and meet the requirements of §60.49Da. Alternatively, data from a NO_Xemission rate (*i.e.* , NO_X-diluent) CEMS certified according to the provisions of §75.20(c) of this chapter and appendix A to part 75 of this chapter, and meeting the quality assurance requirements of §75.21 of this chapter and appendix B to part 75 of this chapter, may be used, with the following caveats. Data used to meet the requirements of §60.51Da shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter. The sampling site shall be located at the outlet from the steam generating unit. The NO_Xemission rate at the outlet from the steam generating unit shall constitute the NO_Xemission rate from the duct burner of the combined cycle system.

(k) *Compliance provisions for duct burners subject to §60.44Da(d)(1) or (e)(1)* . To determine compliance with the emission limitation for NO_Xrequired by §60.44Da(d)(1) or (e)(1) for duct burners used in combined cycle systems, either of the procedures described in paragraphs (k)(1) and (2) of this section may be used:

(1) The owner or operator of an affected duct burner used in combined cycle systems shall determine compliance with the applicable NO_Xemission limitation in §60.44Da(d)(1) or (e)(1) as follows:

(i) The emission rate (E) of NO_Xshall be computed using Equation 2 in this section:

$$E = \frac{(C_{sg} \times Q_{sg}) - (C_{te} \times Q_{te})}{(O_{sg} \times h)} \qquad \text{(Eq. 2)}$$

Where:

E = Emission rate of $NO_X$from the duct burner, ng/J (lb/MWh) gross output;

C_{sg}= Average hourly concentration of NO_Xexiting the steam generating unit, ng/dscm (lb/dscf);

C_{te}= Average hourly concentration of NO_Xin the turbine exhaust upstream from duct burner, ng/dscm (lb/dscf);

Q_{sg}= Average hourly volumetric flow rate of exhaust gas from steam generating unit, dscm/hr (dscf/hr);

Q_{te}= Average hourly volumetric flow rate of exhaust gas from combustion turbine, dscm/hr (dscf/hr);

O_{sg}= Average hourly gross energy output from steam generating unit, J (MWh); and

h = Average hourly fraction of the total heat input to the steam generating unit derived from the combustion of fuel in the affected duct burner.

(ii) Method 7E of appendix A of this part shall be used to determine the NO_Xconcentrations ($C_{sg}$and C_{te}). Method 2, 2F or 2G of appendix A of this part, as appropriate, shall be used to determine the volumetric flow rates ($Q_{sg}$and Q_{te}) of the exhaust gases. The volumetric flow rate measurements shall be taken at the same time as the concentration measurements.

(iii) The owner or operator shall develop, demonstrate, and provide information satisfactory to the Administrator to determine the average hourly gross energy output from the steam generating unit, and the average hourly percentage of the total heat input to the steam generating unit derived from the combustion of fuel in the affected duct burner.

(iv) Compliance with the applicable NO_Xemission limitation in §60.44Da(d)(1) or (e)(1) is determined by the three-run average (nominal 1-hour runs) for the initial and subsequent performance tests.

(2) The owner or operator of an affected duct burner used in a combined cycle system may elect to determine compliance with the applicable NO_Xemission limitation in §60.44Da(d)(1) or (e)(1) on a 30-day rolling average basis as indicated in paragraphs (k)(2)(i) through (iv) of this section.

(i) The emission rate (E) of NO_Xshall be computed using Equation 3 in this section:

$$E = \frac{(C_{sg} \times Q_{sg})}{O_{cc}} \qquad \text{(Eq. 3)}$$

Where:

E = Emission rate of $NO_X$from the duct burner, ng/J (lb/MWh) gross output;

C_{sg}= Average hourly concentration of NO_Xexiting the steam generating unit, ng/dscm (lb/dscf);

Q_{sg}= Average hourly volumetric flow rate of exhaust gas from steam generating unit, dscm/hr (dscf/hr); and

O_{cc}= Average hourly gross energy output from entire combined cycle unit, J (MWh).

(ii) The CEMS specified under §60.49Da for measuring $NO_X$and O_2(or CO_2) shall be used to determine the average hourly NO_Xconcentrations (C_{sg}). The continuous flow monitoring system specified in §60.49Da(l) or §60.49Da(m) shall be used to determine the volumetric flow rate (Q_{sg}) of the exhaust gas. If the option to use the flow monitoring system in §60.49Da(m) is selected, the flow rate data used to meet the requirements of §60.51Da shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter. The sampling site shall be located at the outlet from the steam generating unit.

(iii) The continuous monitoring system specified under §60.49Da(k) for measuring and determining gross energy output shall be used to determine the average hourly gross energy output from the entire combined cycle unit (O_{cc}), which is the combined output from the combustion turbine and the steam generating unit.

(iv) The owner or operator may, in lieu of installing, operating, and recording data from the continuous flow monitoring system specified in §60.49Da(l), determine the mass rate (lb/hr) of NO_Xemissions by installing, operating, and maintaining continuous fuel flowmeters following the appropriate measurements procedures specified in appendix D of part 75 of this chapter. If this compliance option is selected, the emission rate (E) of NO_Xshall be computed using Equation 4 in this section:

$$E = \frac{(ER_{sg} \times H_{cc})}{O_{cc}} \qquad \text{(Eq. 4)}$$

Where:

E = Emission rate of $NO_X$from the duct burner, ng/J (lb/MWh) gross output;

ER_{sg}= Average hourly emission rate of NO_Xexiting the steam generating unit heat input calculated using appropriate F factor as described in Method 19 of appendix A of this part, ng/J (lb/MMBtu);

H_{cc}= Average hourly heat input rate of entire combined cycle unit, J/hr (MMBtu/hr); and

DRAFT

O_{cc}= Average hourly gross energy output from entire combined cycle unit, J (MWh).

(3) When an affected duct burner steam generating unit utilizes a common steam turbine with one or more affected duct burner steam generating units, the owner or operator shall either:

(i) Determine compliance with the applicable NO_Xemissions limits by measuring the emissions combined with the emissions from the other unit(s) utilizing the common steam turbine; or

(ii) Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning the combined gross energy output from the steam turbine for each of the affected duct burners. The Administrator may approve such demonstrated substitute methods for apportioning the combined gross energy output measured at the steam turbine whenever the demonstration ensures accurate estimation of emissions regulated under this part.

(l) *Compliance provisions for sources subject to §60.45Da.* The owner or operator of an affected facility subject to §60.45Da (new sources constructed or reconstructed after January 30, 2004) shall calculate the Hg emission rate (lb/MWh) for each calendar month of the year, using hourly Hg concentrations measured according to the provisions of §60.49Da(p) in conjunction with hourly stack gas volumetric flow rates measured according to the provisions of §60.49Da(l) or (m), and hourly gross electrical outputs, determined according to the provisions in §60.49Da(k). Compliance with the applicable standard under §60.45Da is determined on a 12-month rolling average basis.

(m) *Compliance provisions for sources subject to §60.43Da(i)(1)(i), (i)(2)(i), (i)(3)(i), (j)(1)(i), (j)(2)(i), or (j)(3)(i).* The owner or operator of an affected facility subject to §60.43Da(i)(1)(i), (i)(2)(i), (i)(3)(i), (j)(1)(i), (j)(2)(i), or (j)(3)(i) shall calculate SO_2emissions as 1.660×10^{-7}lb/scf-ppm times the average hourly SO_2output concentration in ppm (measured according to the provisions of §60.49Da(b)), times the average hourly flow rate (measured according to the provisions of §60.49Da(l) or §60.49Da(m)), divided by the average hourly gross energy output (measured according to the provisions of §60.49Da(k)). Alternatively, for oil-fired and gas-fired units, SO_2emissions may be calculated by multiplying the hourly SO_2emission rate (in lb/MMBtu), measured by the CEMS required under §60.49Da, by the hourly heat input rate (measured according to the provisions of §60.49Da(n)), and dividing the result by the average gross energy output (measured according to the provisions of §60.49Da(k)).

(n) *Compliance provisions for sources subject to §60.42Da(c)(1)* . The owner or operator of an affected facility subject to §60.42Da(c)(1) shall calculate PM emissions by multiplying the average hourly PM output concentration (measured according to the provisions of §60.49Da(t)), by the average hourly flow rate (measured according to the provisions of §60.49Da(l) or §60.49Da(m)), and divided by the average hourly gross energy output (measured according to the provisions of §60.49Da(k)). Compliance with the emission limit is determined by calculating the arithmetic average of the hourly emission rates computed for each boiler operating day.

(o) *Compliance provisions for sources subject to §60.42Da(c)(2) or (d)* . Except as provided for in paragraph (p) of this section, the owner or operator of an affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, shall demonstrate compliance with each applicable emission limit according to the requirements in paragraphs (o)(1) through (o)(5) of this section.

(1) You must conduct a performance test to demonstrate initial compliance with the applicable PM emissions limit in §60.42Da(c)(2) or (d) by the applicable date specified in §60.8(a). Thereafter, you must conduct each subsequent performance test within 12 calendar months following the date the previous performance test was required to be conducted. You must conduct each performance test according to the requirements in §60.8 using the test methods and procedures in §60.50Da. The owner or operator of an affected facility that has not operated for 60 consecutive calendar days prior to the date that the subsequent performance test would have been required had the unit been operating is not required to perform the subsequent performance test until 30

DRAFT

calendar days after the next boiler operating day. Requests for additional 30 day extensions shall be granted by the relevant air division or office director of the appropriate Regional Office of the U.S. EPA.

(2) You must monitor the performance of each electrostatic precipitator or fabric filter (baghouse) operated to comply with the applicable PM emissions limit in §60.42Da(c)(2) or (d) using a continuous opacity monitoring system (COMS) according to the requirements in paragraphs (o)(2)(i) through (vi) unless you elect to comply with one of the alternatives provided in paragraphs (o)(3) and (o)(4) of this section, as applicable to your control device.

(i) Each COMS must meet Performance Specification 1 in 40 CFR part 60, appendix B.

(ii) You must comply with the quality assurance requirements in paragraphs (o)(2)(ii)(A) through (E) of this section.

(A) You must automatically (intrinsic to the opacity monitor) check the zero and upscale (span) calibration drifts at least once daily. For a particular COMS, the acceptable range of zero and upscale calibration materials is as defined in the applicable version of Performance Specification 1 in 40 CFR part 60, appendix B.

(B) You must adjust the zero and span whenever the 24-hour zero drift or 24-hour span drift exceeds 4 percent opacity. The COMS must allow for the amount of excess zero and span drift measured at the 24-hour interval checks to be recorded and quantified. The optical surfaces exposed to the effluent gases must be cleaned prior to performing the zero and span drift adjustments, except for systems using automatic zero adjustments. For systems using automatic zero adjustments, the optical surfaces must be cleaned when the cumulative automatic zero compensation exceeds 4 percent opacity.

(C) You must apply a method for producing a simulated zero opacity condition and an upscale (span) opacity condition using a certified neutral density filter or other related technique to produce a known obscuration of the light beam. All procedures applied must provide a system check of the analyzer internal optical surfaces and all electronic circuitry including the lamp and photodetector assembly.

(D) Except during periods of system breakdowns, repairs, calibration checks, and zero and span adjustments, the COMS must be in continuous operation and must complete a minimum of one cycle of sampling and analyzing for each successive 10 second period and one cycle of data recording for each successive 6-minute period.

(E) You must reduce all data from the COMS to 6-minute averages. Six-minute opacity averages must be calculated from 36 or more data points equally spaced over each 6-minute period. Data recorded during periods of system breakdowns, repairs, calibration checks, and zero and span adjustments must not be included in the data averages. An arithmetic or integrated average of all data may be used.

(iii) During each performance test conducted according to paragraph (o)(1) of this section, you must establish an opacity baseline level. The value of the opacity baseline level is determined by averaging all of the 6-minute average opacity values (reported to the nearest 0.1 percent opacity) from the COMS measurements recorded during each of the test run intervals conducted for the performance test, and then adding 2.5 percent opacity to your calculated average opacity value for all of the test runs. If your opacity baseline level is less than 5.0 percent, then the opacity baseline level is set at 5.0 percent.

(iv) You must evaluate the preceding 24-hour average opacity level measured by the COMS each boiler operating day excluding periods of affected facility startup, shutdown, or malfunction. If the measured 24-hour average opacity emission level is greater than the baseline opacity level determined in paragraph (o)(2)(iii) of this section, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high opacity incident and take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the measured 24-hour average opacity to a level below

DRAFT

the baseline opacity level. In cases when a wet scrubber is used in combination with another PM control device that serves as the primary PM control device, the wet scrubber must be maintained and operated.

(v) You must record the opacity measurements, calculations performed, and any corrective actions taken. The record of corrective action taken must include the date and time during which the measured 24-hour average opacity was greater than baseline opacity level, and the date, time, and description of the corrective action.

(vi) If the measured 24-hour average opacity for your affected facility remains at a level greater than the opacity baseline level after 7 boiler operating days, then you must conduct a new PM performance test according to paragraph (o)(1) of this section and establish a new opacity baseline value according to paragraph (o)(2) of this section. This new performance test must be conducted within 60 days of the date that the measured 24-hour average opacity was first determined to exceed the baseline opacity level unless a waiver is granted by the permitting authority.

(3) As an alternative to complying with the requirements of paragraph (o)(2) of this section, an owner or operator may elect to monitor the performance of an electrostatic precipitator (ESP) operated to comply with the applicable PM emissions limit in §60.42Da(c)(2) or (d) using an ESP predictive model developed in accordance with the requirements in paragraphs (o)(3)(i) through (v) of this section.

(i) You must calibrate the ESP predictive model with each PM control device used to comply with the applicable PM emissions limit in §60.42Da(c)(2) or (d) operating under normal conditions. In cases when a wet scrubber is used in combination with an ESP to comply with the PM emissions limit, the wet scrubber must be maintained and operated.

(ii) You must develop a site-specific monitoring plan that includes a description of the ESP predictive model used, the model input parameters, and the procedures and criteria for establishing monitoring parameter baseline levels indicative of compliance with the PM emissions limit. You must submit the site-specific monitoring plan for approval by the permitting authority. For reference purposes in preparing the monitoring plan, see the OAQPS "Compliance Assurance Monitoring (CAM) Protocol for an Electrostatic Precipitator (ESP) Controlling Particulate Matter (PM) Emissions from a Coal-Fired Boiler." This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality Planning and Standards; Sector Policies and Programs Division; Measurement Policy Group (D243–02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Continuous Emission Monitoring.

(iii) You must run the ESP predictive model using the applicable input data each boiler operating day and evaluate the model output for the preceding boiler operating day excluding periods of affected facility startup, shutdown, or malfunction. If the values for one or more of the model parameters exceed the applicable baseline levels determined according to your approved site-specific monitoring plan, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of a model parameter deviation and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to return the model output to within the applicable baseline levels.

(iv) You must record the ESP predictive model inputs and outputs and any corrective actions taken. The record of corrective action taken must include the date and time during which the model output values exceeded the applicable baseline levels, and the date, time, and description of the corrective action.

(v) If after 7 consecutive days a model parameter continues to exceed the applicable baseline level, then you must conduct a new PM performance test according to paragraph (o)(1) of this section. This new performance test must be conducted within 60 calendar days of the date that the model parameter was first determined to exceed its baseline level unless a waiver is granted by the permitting authority.

(4) As an alternative to complying with the requirements of paragraph (o)(2) of this section, an owner or operator may elect to monitor the performance of a fabric filter (baghouse) operated to comply with the

DRAFT

applicable PM emissions limit in §60.42Da(c)(2) or (d) by using a bag leak detection system according to the requirements in paragraphs (o)(4)(i) through (v) of this section.

(i) Each bag leak detection system must meet the specifications and requirements in paragraphs (o)(4)(i)(A) through (H) of this section.

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

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

(C) The bag leak detection system must be equipped with an alarm system that will react when the system detects an increase in relative particulate loading over the alarm set point established according to paragraph (o)(4)(i)(D) of this section, and the alarm must be located such that it can be noticed by the appropriate plant personnel.

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

(E) Following initial adjustment, you must not adjust the averaging period, alarm set point, or alarm delay time without approval from the permitting authority except as provided in paragraph (d)(1)(vi) of this section.

(F) Once per quarter, you may adjust the sensitivity of the bag leak detection system to account for seasonal effects, including temperature and humidity, according to the procedures identified in the site-specific monitoring plan required by paragraph (o)(4)(ii) of this section.

(G) You must install the bag leak detection sensor downstream of the fabric filter and upstream of any wet scrubber.

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

(ii) You must develop and submit to the permitting authority for approval a site-specific monitoring plan for each bag leak detection system. You must operate and maintain the bag leak detection system according to the site-specific monitoring plan at all times. Each monitoring plan must describe the items in paragraphs (o)(4)(ii)(A) through (F) of this section.

(A) Installation of the bag leak detection system;

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

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

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

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

(F) Corrective action procedures as specified in paragraph (o)(4)(iii) of this section. In approving the site-specific monitoring plan, the permitting authority may allow owners and operators more than 3 hours to alleviate a specific condition that causes an alarm if the owner or operator identifies in the monitoring plan this specific condition as one that could lead to an alarm, adequately explains why it is not feasible to alleviate this condition within 3 hours of the time the alarm occurs, and demonstrates that the requested time will ensure alleviation of this condition as expeditiously as practicable.

DRAFT

(iii) For each bag leak detection system, you must initiate procedures to determine the cause of every alarm within 1 hour of the alarm. Except as provided in paragraph (o)(4)(ii)(F) of this section, you must alleviate the cause of the alarm within 3 hours of the alarm by taking whatever corrective action(s) are necessary. Corrective actions may include, but are not limited to the following:

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

(B) Sealing off defective bags or filter media;

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

(D) Sealing off a defective fabric filter compartment;

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

(F) Shutting down the process producing the particulate emissions.

(iv) You must maintain records of the information specified in paragraphs (o)(4)(iv)(A) through (C) of this section for each bag leak detection system.

(A) Records of the bag leak detection system output;

(B) Records of bag leak detection system adjustments, including the date and time of the adjustment, the initial bag leak detection system settings, and the final bag leak detection system settings; and

(C) The date and time of all bag leak detection system alarms, the time that procedures to determine the cause of the alarm were initiated, if procedures were initiated within 1 hour of the alarm, the cause of the alarm, an explanation of the actions taken, the date and time the cause of the alarm was alleviated, and if the alarm was alleviated within 3 hours of the alarm.

(v) If after any period composed of 30 boiler operating days during which the alarm rate exceeds 5 percent of the process operating time (excluding control device or process startup, shutdown, and malfunction), then you must conduct a new PM performance test according to paragraph (o)(1) of this section. This new performance test must be conducted within 60 calendar days of the date that the alarm rate was first determined to exceed 5 percent limit unless a waiver is granted by the permitting authority.

(5) An owner or operator of a modified affected facility electing to meet the emission limitations in §60.42Da(d) shall determine the percent reduction in PM by using the emission rate for PM determined by the performance test conducted according to the requirements in paragraph (o)(1) of this section and the ash content on a mass basis of the fuel burned during each performance test run as determined by analysis of the fuel as fired.

(p) As an alternative to meeting the compliance provisions specified in paragraph (o) of this section, an owner or operator may elect to install, evaluate, maintain, and operate a CEMS measuring PM emissions discharged from the affected facility to the atmosphere and record the output of the system as specified in paragraphs (p)(1) through (p)(8) of this section.

(1) The owner or operator shall submit a written notification to the Administrator of intent to demonstrate compliance with this subpart by using a CEMS measuring PM. This notification shall be sent at least 30 calendar days before the initial startup of the monitor for compliance determination purposes. The owner or operator may discontinue operation of the monitor and instead return to demonstration of compliance with this subpart according to the requirements in paragraph (o) of this section by submitting written notification to the Administrator of such intent at least 30 calendar days before shutdown of the monitor for compliance determination purposes.

(2) Each CEMS shall be installed, evaluated, operated, and maintained according to the requirements in §60.49Da(v).

(3) The initial performance evaluation shall be completed no later than 180 days after the date of initial startup of the affected facility, as specified under §60.8 of subpart A of this part or within 180 days of the date of notification to the Administrator required under paragraph (p)(1) of this section, whichever is later.

(4) Compliance with the applicable emissions limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emissions concentrations using the continuous monitoring system outlet data. The 24-hour block arithmetic average emission concentration shall be calculated using EPA Reference Method 19 of appendix A of this part, section 4.1.

(5) At a minimum, valid CEMS hourly averages shall be obtained for 75 percent of all operating hours on a 30-day rolling average basis. Beginning on January 1, 2012, valid CEMS hourly averages shall be obtained for 90 percent of all operating hours on a 30-day rolling average basis.

(i) At least two data points per hour shall be used to calculate each 1-hour arithmetic average.

(ii) [Reserved]

(6) The 1-hour arithmetic averages required shall be expressed in ng/J, MMBtu/hr, or lb/MWh and shall be used to calculate the boiler operating day daily arithmetic average emission concentrations. The 1-hour arithmetic averages shall be calculated using the data points required under §60.13(e)(2) of subpart A of this part.

(7) All valid CEMS data shall be used in calculating average emission concentrations even if the minimum CEMS data requirements of paragraph (j)(5) of this section are not met.

(8) When PM emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 of appendix A of this part to provide, as necessary, valid emissions data for a minimum of 90 percent (only 75 percent is required prior to January 1, 2012) of all operating hours per 30-day rolling average.

(q) *Compliance provisions for sources subject to §60.42Da(b)* . An owner or operator of an affected facility subject to the opacity standard in §60.42Da(b) shall monitor the opacity of emissions discharged from the affected facility to the atmosphere according to the requirements in §60.49Da(a), as applicable to the affected facility.

[72 FR 32722, June 13, 2007, as amended at 74 FR 5079, Jan. 28, 2009]

§ 60.49Da Emission monitoring.

(a) An owner or operator of an affected facility subject to the opacity standard in §60.42Da(b) shall monitor the opacity of emissions discharged from the affected facility to the atmosphere according to the applicable requirements in paragraphs (a)(1) through (3) of this section.

(1) Except as provided for in paragraph (a)(2) of this section, the owner or operator of an affected facility, shall install, calibrate, maintain, and operate a COMS, and record the output of the system, for measuring the opacity of emissions discharged to the atmosphere. If opacity interference due to water droplets exists in the stack (for example, from the use of an FGD system), the opacity is monitored upstream of the interference (at the inlet to the FGD system). If opacity interference is experienced at all locations (both at the inlet and outlet of the SO_2control system), alternate parameters indicative of the PM control system's performance and/or good combustion are monitored (subject to the approval of the Administrator).

(2) As an alternative to the monitoring requirements in paragraph (a)(1) of this section, an owner or operator of an affected facility that meets the conditions in either paragraph (a)(2)(i), (ii), or (iii) of this section may elect to monitor opacity as specified in paragraph (a)(3) of this section.

(i) The affected facility uses a fabric filter (baghouse) to meet the standards in §60.42Da and a bag leak detection system is installed and operated according to the requirements in paragraphs §60.48Da(o)(4)(i) through (v);

(ii) The affected facility burns only gaseous or liquid fuels (excluding residual oil) with potential SO_2emissions rates of 26 ng/J (0.060 lb/MMBtu) or less, and does not use a post-combustion technology to reduce emissions of SO_2or PM; or

(iii) The affected facility meets all of the conditions specified in paragraphs (a)(2)(iii)(A) through (C) of this section.

(A) No post-combustion technology (except a wet scrubber) is used for reducing PM, SO_2, or carbon monoxide (CO) emissions;

(B) Only natural gas, gaseous fuels, or fuel oils that contain less than or equal to 0.30 weight percent sulfur are burned; and

(C) Emissions of CO discharged to the atmosphere are maintained at levels less than or equal to 1.4 lb/MWh on a boiler operating day average basis as demonstrated by the use of a CEMS measuring CO emissions according to the procedures specified in paragraph (u) of this section.

(3) The owner or operators of an affected facility that meets the conditions in paragraph (a)(2) of this section may, as an alternative to COMS, elect to monitor visible emissions using the applicable procedures specified in paragraphs (a)(3)(i) through (iv) of this section.

(i) The owner or operator shall conduct a performance test using Method 9 of appendix A–4 of this part and the procedures in §60.11. If during the initial 60 minutes of the observation all the 6-minute averages are less than 10 percent and all the individual 15-second observations are less than or equal to 20 percent, then the observation period may be reduced from 3 hours to 60 minutes.

(ii) Except as provided in paragraph (a)(3)(iii) or (iv) of this section, the owner or operator shall conduct subsequent Method 9 of appendix A–4 of this part performance tests using the procedures in paragraph (a)(3)(i) of this section according to the applicable schedule in paragraphs (a)(3)(ii)(A) through (a)(3)(ii)(D) of this section, as determined by the most recent Method 9 of appendix A–4 of this part performance test results.

(A) If no visible emissions are observed, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted;

(B) If visible emissions are observed but the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 6 calendar months from the date that the most recent performance test was conducted;

(C) If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 3 calendar months from the date that the most recent performance test was conducted; or

(D) If the maximum 6-minute average opacity is greater than 10 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 30 calendar days from the date that the most recent performance test was conducted.

DRAFT

(iii) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A–4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A–4 of this part performance tests, elect to perform subsequent monitoring using Method 22 of appendix A–7 of this part according to the procedures specified in paragraphs (a)(3)(iii)(A) and (B) of this section.

(A) The owner or operator shall conduct 10 minute observations (during normal operation) each operating day the affected facility fires fuel for which an opacity standard is applicable using Method 22 of appendix A–7 of this part and demonstrate that the sum of the occurrences of any visible emissions is not in excess of 5 percent of the observation period (*i.e.* , 30 seconds per 10 minute period). If the sum of the occurrence of any visible emissions is greater than 30 seconds during the initial 10 minute observation, immediately conduct a 30 minute observation. If the sum of the occurrence of visible emissions is greater than 5 percent of the observation period (*i.e.* , 90 seconds per 30 minute period) the owner or operator shall either document and adjust the operation of the facility and demonstrate within 24 hours that the sum of the occurrence of visible emissions is equal to or less than 5 percent during a 30 minute observation (*i.e.* , 90 seconds) or conduct a new Method 9 of appendix A–4 of this part performance test using the procedures in paragraph (a)(3)(i) of this section within 30 calendar days according to the requirements in §60.50Da(b)(3).

(B) If no visible emissions are observed for 30 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

(iv) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A–4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A–4 performance tests, elect to perform subsequent monitoring using a digital opacity compliance system according to a site-specific monitoring plan approved by the Administrator. The observations shall be similar, but not necessarily identical, to the requirements in paragraph (a)(3)(iii) of this section. For reference purposes in preparing the monitoring plan, see OAQPS "Determination of Visible Emission Opacity from Stationary Sources Using Computer-Based Photographic Analysis Systems." This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality and Planning Standards; Sector Policies and Programs Division; Measurement Policy Group (D243–02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Preliminary Methods.

(b) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring SO_2emissions, except where natural gas is the only fuel combusted, as follows:

(1) Sulfur dioxide emissions are monitored at both the inlet and outlet of the SO_2control device.

(2) For a facility that qualifies under the numerical limit provisions of §60.43Da(d), (i), (j), or (k) SO_2emissions are only monitored as discharged to the atmosphere.

(3) An "as fired" fuel monitoring system (upstream of coal pulverizers) meeting the requirements of Method 19 of appendix A of this part may be used to determine potential SO_2emissions in place of a continuous SO_2emission monitor at the inlet to the SO_2control device as required under paragraph (b)(1) of this section.

(4) If the owner or operator has installed and certified a SO_2CEMS according to the requirements of §75.20(c)(1) of this chapter and appendix A to part 75 of this chapter, and is continuing to meet the ongoing quality assurance requirements of §75.21 of this chapter and appendix B to part 75 of this chapter, that CEMS may be used to meet the requirements of this section, provided that:

(i) A CO_2or O_2continuous monitoring system is installed, calibrated, maintained and operated at the same location, according to paragraph (d) of this section; and

DRAFT

(ii) For sources subject to an SO_2emission limit in lb/MMBtu under §60.43Da:

(A) When relative accuracy testing is conducted, SO_2concentration data and CO_2(or O_2) data are collected simultaneously; and

(B) In addition to meeting the applicable $SO_2$and CO_2(or O_2) relative accuracy specifications in Figure 2 of appendix B to part 75 of this chapter, the relative accuracy (RA) standard in section 13.2 of Performance Specification 2 in appendix B to this part is met when the RA is calculated on a lb/MMBtu basis; and

(iii) The reporting requirements of §60.51Da are met. The $SO_2$and, if required, CO_2(or O_2) data reported to meet the requirements of §60.51Da shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the SO_2data have been bias adjusted according to the procedures of part 75 of this chapter.

(c)(1) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring NO_Xemissions discharged to the atmosphere; or

(2) If the owner or operator has installed a NO_Xemission rate CEMS to meet the requirements of part 75 of this chapter and is continuing to meet the ongoing requirements of part 75 of this chapter, that CEMS may be used to meet the requirements of this section, except that the owner or operator shall also meet the requirements of §60.51Da. Data reported to meet the requirements of §60.51Da shall not include data substituted using the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(d) The owner or operator of an affected facility not complying with an output based limit shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring the O_2or carbon dioxide (CO_2) content of the flue gases at each location where SO_2or NO_Xemissions are monitored. For affected facilities subject to a lb/MMBtu SO_2emission limit under §60.43Da, if the owner or operator has installed and certified a CO_2or O_2monitoring system according to §75.20(c) of this chapter and appendix A to part 75 of this chapter and the monitoring system continues to meet the applicable quality-assurance provisions of §75.21 of this chapter and appendix B to part 75 of this chapter, that CEMS may be used together with the part 75 SO_2concentration monitoring system described in paragraph (b) of this section, to determine the SO_2emission rate in lb/MMBtu. SO_2data used to meet the requirements of §60.51Da shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(e) The CEMS under paragraphs (b), (c), and (d) of this section are operated and data recorded during all periods of operation of the affected facility including periods of startup, shutdown, malfunction or emergency conditions, except for CEMS breakdowns, repairs, calibration checks, and zero and span adjustments.

(f)(1) For units that began construction, reconstruction, or modification on or before February 28, 2005, the owner or operator shall obtain emission data for at least 18 hours in at least 22 out of 30 successive boiler operating days. If this minimum data requirement cannot be met with CEMS, the owner or operator shall supplement emission data with other monitoring systems approved by the Administrator or the reference methods and procedures as described in paragraph (h) of this section.

(2) For units that began construction, reconstruction, or modification after February 28, 2005, the owner or operator shall obtain emission data for at least 90 percent of all operating hours for each 30 successive boiler operating days. If this minimum data requirement cannot be met with a CEMS, the owner or operator shall supplement emission data with other monitoring systems approved by the Administrator or the reference methods and procedures as described in paragraph (h) of this section.

DRAFT

(g) The 1-hour averages required under paragraph §60.13(h) are expressed in ng/J (lb/MMBtu) heat input and used to calculate the average emission rates under §60.48Da. The 1-hour averages are calculated using the data points required under §60.13(h)(2).

(h) When it becomes necessary to supplement CEMS data to meet the minimum data requirements in paragraph (f) of this section, the owner or operator shall use the reference methods and procedures as specified in this paragraph. Acceptable alternative methods and procedures are given in paragraph (j) of this section.

(1) Method 6 of appendix A of this part shall be used to determine the SO_2concentration at the same location as the SO_2monitor. Samples shall be taken at 60-minute intervals. The sampling time and sample volume for each sample shall be at least 20 minutes and 0.020 dscm (0.71 dscf). Each sample represents a 1-hour average.

(2) Method 7 of appendix A of this part shall be used to determine the NO_Xconcentration at the same location as the NO_Xmonitor. Samples shall be taken at 30-minute intervals. The arithmetic average of two consecutive samples represents a 1-hour average.

(3) The emission rate correction factor, integrated bag sampling and analysis procedure of Method 3B of appendix A of this part shall be used to determine the O_2or CO_2concentration at the same location as the O_2or CO_2monitor. Samples shall be taken for at least 30 minutes in each hour. Each sample represents a 1-hour average.

(4) The procedures in Method 19 of appendix A of this part shall be used to compute each 1-hour average concentration in ng/J (lb/MMBtu) heat input.

(i) The owner or operator shall use methods and procedures in this paragraph to conduct monitoring system performance evaluations under §60.13(c) and calibration checks under §60.13(d). Acceptable alternative methods and procedures are given in paragraph (j) of this section.

(1) Methods 3B, 6, and 7 of appendix A of this part shall be used to determine O_2, SO_2, and NO_Xconcentrations, respectively.

(2) SO_2or NO_X(NO), as applicable, shall be used for preparing the calibration gas mixtures (in N_2, as applicable) under Performance Specification 2 of appendix B of this part.

(3) For affected facilities burning only fossil fuel, the span value for a COMS is between 60 and 80 percent. Span values for a CEMS measuring NO_Xshall be determined using one of the following procedures:

(i) Except as provided under paragraph (i)(3)(ii) of this section, NO_Xspan values shall be determined as follows:

Fossil fuel	**Span values for NO_X (ppm)**
Gas	500.
Liquid	500.
Solid	1,000.
Combination	500 (x + y) + 1,000z.

Where:

x = Fraction of total heat input derived from gaseous fossil fuel,

DRAFT

y = Fraction of total heat input derived from liquid fossil fuel, and

z = Fraction of total heat input derived from solid fossil fuel.

(ii) As an alternative to meeting the requirements of paragraph (i)(3)(i) of this section, the owner or operator of an affected facility may elect to use the NO_Xspan values determined according to section 2.1.2 in appendix A to part 75 of this chapter.

(4) All span values computed under paragraph (i)(3)(i) of this section for burning combinations of fossil fuels are rounded to the nearest 500 ppm. Span values computed under paragraph (i)(3)(ii) of this section shall be rounded off according to section 2.1.2 in appendix A to part 75 of this chapter.

(5) For affected facilities burning fossil fuel, alone or in combination with non-fossil fuel and determining span values under paragraph (i)(3)(i) of this section, the span value of the SO_2CEMS at the inlet to the SO_2control device is 125 percent of the maximum estimated hourly potential emissions of the fuel fired, and the outlet of the SO_2control device is 50 percent of maximum estimated hourly potential emissions of the fuel fired. For affected facilities determining span values under paragraph (i)(3)(ii) of this section, SO_2span values shall be determined according to section 2.1.1 in appendix A to part 75 of this chapter.

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

(1) For Method 6 of appendix A of this part, Method 6A or 6B (whenever Methods 6 and 3 or 3B of appendix A of this part data are used) or 6C of appendix A of this part may be used. Each Method 6B of appendix A of this part sample obtained over 24 hours represents 24 1-hour averages. If Method 6A or 6B of appendix A of this part is used under paragraph (i) of this section, the conditions under §60.48Da(d)(1) apply; these conditions do not apply under paragraph (h) of this section.

(2) For Method 7 of appendix A of this part, Method 7A, 7C, 7D, or 7E of appendix A of this part may be used. If Method 7C, 7D, or 7E of appendix A of this part is used, the sampling time for each run shall be 1 hour.

(3) For Method 3 of appendix A of this part, Method 3A or 3B of appendix A of this part may be used if the sampling time is 1 hour.

(4) For Method 3B of appendix A of this part, Method 3A of appendix A of this part may be used.

(k) The procedures specified in paragraphs (k)(1) through (3) of this section shall be used to determine gross output for sources demonstrating compliance with the output-based standard under §§60.42Da(c), 60.43Da(i), 60.43Da(j), 60.44Da(d)(1), and 60.44Da(e).

(1) The owner or operator of an affected facility with electricity generation shall install, calibrate, maintain, and operate a wattmeter; measure gross electrical output in MWh on a continuous basis; and record the output of the monitor.

(2) The owner or operator of an affected facility with process steam generation shall install, calibrate, maintain, and operate meters for steam flow, temperature, and pressure; measure gross process steam output in joules per hour (or Btu per hour) on a continuous basis; and record the output of the monitor.

(3) For affected facilities generating process steam in combination with electrical generation, the gross energy output is determined from the gross electrical output measured in accordance with paragraph (k)(1) of this section plus 75 percent of the gross thermal output (measured relative to ISO conditions) of the process steam measured in accordance with paragraph (k)(2) of this section.

(l) The owner or operator of an affected facility demonstrating compliance with an output-based standard under §60.42Da, §60.43Da, §60.44Da, or §60.45Da shall install, certify, operate, and maintain a continuous flow monitoring system meeting the requirements of Performance Specification 6 of appendix B of this part and the

DRAFT

CD assessment, RATA and reporting provisions of procedure 1 of appendix F of this part, and record the output of the system, for measuring the volumetric flow rate of exhaust gases discharged to the atmosphere; or

(m) Alternatively, data from a continuous flow monitoring system certified according to the requirements of §75.20(c) of this chapter and appendix A to part 75 of this chapter, and continuing to meet the applicable quality control and quality assurance requirements of §75.21 of this chapter and appendix B to part 75 of this chapter, may be used. Flow rate data reported to meet the requirements of §60.51Da shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(n) Gas-fired and oil-fired units. The owner or operator of an affected unit that qualifies as a gas-fired or oil-fired unit, as defined in 40 CFR 72.2, may use, as an alternative to the requirements specified in either paragraph (l) or (m) of this section, a fuel flow monitoring system certified and operated according to the requirements of appendix D of part 75 of this chapter.

(o) The owner or operator of a duct burner, as described in §60.41Da, which is subject to the NO_Xstandards of §60.44Da(a)(1), (d)(1), or (e)(1) is not required to install or operate a CEMS to measure NO_Xemissions; a wattmeter to measure gross electrical output; meters to measure steam flow, temperature, and pressure; and a continuous flow monitoring system to measure the flow of exhaust gases discharged to the atmosphere.

(p) The owner or operator of an affected facility demonstrating compliance with an Hg limit in §60.45Da shall install and operate a CEMS to measure and record the concentration of Hg in the exhaust gases from each stack according to the requirements in paragraphs (p)(1) through (p)(3) of this section. Alternatively, for an affected facility that is also subject to the requirements of subpart I of part 75 of this chapter, the owner or operator may install, certify, maintain, operate and quality-assure the data from a Hg CEMS according to §75.10 of this chapter and appendices A and B to part 75 of this chapter, in lieu of following the procedures in paragraphs (p)(1) through (p)(3) of this section.

(1) The owner or operator must install, operate, and maintain each CEMS according to Performance Specification 12A in appendix B to this part.

(2) The owner or operator must conduct a performance evaluation of each CEMS according to the requirements of §60.13 and Performance Specification 12A in appendix B to this part.

(3) The owner or operator must operate each CEMS according to the requirements in paragraphs (p)(3)(i) through (iv) of this section.

(i) As specified in §60.13(e)(2), each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(ii) The owner or operator must reduce CEMS data as specified in §60.13(h).

(iii) The owner or operator shall use all valid data points collected during the hour to calculate the hourly average Hg concentration.

(iv) The owner or operator must record the results of each required certification and quality assurance test of the CEMS.

(4) Mercury CEMS data collection must conform to paragraphs (p)(4)(i) through (iv) of this section.

(i) For each calendar month in which the affected unit operates, valid hourly Hg concentration data, stack gas volumetric flow rate data, moisture data (if required), and electrical output data (i.e., valid data for all of these parameters) shall be obtained for at least 75 percent of the unit operating hours in the month.

(ii) Data reported to meet the requirements of this subpart shall not include hours of unit startup, shutdown, or malfunction. In addition, for an affected facility that is also subject to subpart I of part 75 of this chapter, data

DRAFT

reported to meet the requirements of this subpart shall not include data substituted using the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(iii) If valid data are obtained for less than 75 percent of the unit operating hours in a month, you must discard the data collected in that month and replace the data with the mean of the individual monthly emission rate values determined in the last 12 months. In the 12-month rolling average calculation, this substitute Hg emission rate shall be weighted according to the number of unit operating hours in the month for which the data capture requirement of §60.49Da(p)(4)(i) was not met.

(iv) Notwithstanding the requirements of paragraph (p)(4)(iii) of this section, if valid data are obtained for less than 75 percent of the unit operating hours in another month in that same 12-month rolling average cycle, discard the data collected in that month and replace the data with the highest individual monthly emission rate determined in the last 12 months. In the 12-month rolling average calculation, this substitute Hg emission rate shall be weighted according to the number of unit operating hours in the month for which the data capture requirement of §60.49Da(p)(4)(i) was not met.

(q) As an alternative to the CEMS required in paragraph (p) of this section, the owner or operator may use a sorbent trap monitoring system (as defined in §72.2 of this chapter) to monitor Hg concentration, according to the procedures described in §75.15 of this chapter and appendix K to part 75 of this chapter.

(r) For Hg CEMS that measure Hg concentration on a dry basis or for sorbent trap monitoring systems, the emissions data must be corrected for the stack gas moisture content. A certified continuous moisture monitoring system that meets the requirements of §75.11(b) of this chapter is acceptable for this purpose. Alternatively, the appropriate default moisture value, as specified in §75.11(b) or §75.12(b) of this chapter, may be used.

(s) The owner or operator shall prepare and submit to the Administrator for approval a unit-specific monitoring plan for each monitoring system, at least 45 days before commencing certification testing of the monitoring systems. The owner or operator shall comply with the requirements in your plan. The plan must address the requirements in paragraphs (s)(1) through (6) of this section.

(1) Installation of the CEMS sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of the exhaust emissions (*e.g.* , on or downstream of the last control device);

(2) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems;

(3) Performance evaluation procedures and acceptance criteria (*e.g.*, calibrations, relative accuracy test audits (RATA), etc.);

(4) Ongoing operation and maintenance procedures in accordance with the general requirements of §60.13(d) or part 75 of this chapter (as applicable);

(5) Ongoing data quality assurance procedures in accordance with the general requirements of §60.13 or part 75 of this chapter (as applicable); and

(6) Ongoing recordkeeping and reporting procedures in accordance with the requirements of this subpart.

(t) The owner or operator of an affected facility demonstrating compliance with the output-based emissions limitation under §60.42Da(c)(1) shall install, certify, operate, and maintain a CEMS for measuring PM emissions according to the requirements of paragraph (v) of this section. An owner or operator of an affected facility demonstrating compliance with the input-based emission limitation in §60.42Da(a)(1) or §60.42Da(c)(2) may install, certify, operate, and maintain a CEMS for measuring PM emissions according to the requirements of paragraph (v) of this section.

DRAFT

(u) The owner or operator of an affected facility using a CEMS measuring CO emissions to meet requirements of this subpart shall meet the requirements specified in paragraphs (u)(1) through (4) of this section.

(1) You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (u)(1)(i) through (iv) of this section.

(i) The CO CEMS must be installed, certified, maintained, and operated according to the provisions in §60.58b(i)(3) of subpart Eb of this part.

(ii) Each 1-hour CO emissions average is calculated using the data points generated by the CO CEMS expressed in parts per million by volume corrected to 3 percent oxygen (dry basis).

(iii) At a minimum, valid 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30-day rolling average basis. The 1-hour averages are calculated using the data points required in §60.13(h)(2).

(iv) Quarterly accuracy determinations and daily calibration drift tests for the CO CEMS must be performed in accordance with procedure 1 in appendix F of this part.

(2) You must calculate the 1-hour average CO emissions levels for each boiler operating day by multiplying the average hourly CO output concentration measured by the CO CEMS times the corresponding average hourly flue gas flow rate and divided by the corresponding average hourly useful energy output from the affected facility. The 24-hour average CO emission level is determined by calculating the arithmetic average of the hourly CO emission levels computed for each boiler operating day.

(3) You must evaluate the preceding 24-hour average CO emission level each boiler operating day excluding periods of affected facility startup, shutdown, or malfunction. If the 24-hour average CO emission level is greater than 1.4 lb/MWh, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high emission incident and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the 24-hour average CO emission level to 1.4 lb/MWh or less.

(4) You must record the CO measurements and calculations performed according to paragraph (u)(3) of this section and any corrective actions taken. The record of corrective action taken must include the date and time during which the 24-hour average CO emission level was greater than 1.4 lb/MWh, and the date, time, and description of the corrective action.

(v) The owner or operator of an affected facility using a CEMS measuring PM emissions to meet requirements of this subpart shall install, certify, operate, and maintain the CEMS as specified in paragraphs (v)(1) through (v)(4) of this section.

(1) The owner or operator shall conduct a performance evaluation of the CEMS according to the applicable requirements of §60.13, Performance Specification 11 in appendix B of this part, and procedure 2 in appendix F of this part.

(2) During each PM correlation testing run of the CEMS required by Performance Specification 11 in appendix B of this part, PM and O_2(or CO_2) data shall be collected concurrently (or within a 30- to 60-minute period) by both the CEMS and performance tests conducted using the following test methods.

(i) For PM, Method 5 or 5B of appendix A–3 of this part or Method 17 of appendix A–6 of this part shall be used; and

(ii) After July 1, 2010 or after Method 202 of appendix M of part 51 has been revised to minimize artifact measurement and notice of that change has been published in theFederal Register,whichever is later, for condensable PM emissions, Method 202 of appendix M of part 51 shall be used; and

DRAFT

(iii) For O_2(or CO_2), Method 3A or 3B of appendix A–2 of this part, as applicable shall be used.

(3) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 2 in appendix F of this part. Relative Response Audit's must be performed annually and Response Correlation Audits must be performed every 3 years.

(4) After July 1, 2011, within 90 days after the date of completing each performance evaluation required by paragraph (v) of this section, the owner or operator of the affected facility must either submit the test data to EPA by successfully entering the data electronically into EPA's WebFIRE data base available at *http://cfpub.epa.gov/oarweb/index.cfm?action=fire.main* or mail a copy to: United States Environmental Protection Agency; Energy Strategies Group; 109 TW Alexander DR; Mail Code: D243–01; RTP, NC 27711.

(w) The owner or operator using a SO_2, NO_X, CO_2, and O_2CEMS to meet the requirements of this subpart shall install, certify, operate, and maintain the CEMS as specified in paragraphs (w)(1) through (w)(5) of this section.

(1) Except as provided for under paragraphs (w)(2), (w)(3), and (w)(4) of this section, each SO_2, NO_X, CO_2, and O_2CEMS required under paragraphs (b) through (d) of this section shall be installed, certified, and operated in accordance with the applicable procedures in Performance Specification 2 or 3 in appendix B to this part or according to the procedures in appendices A and B to part 75 of this chapter. Daily calibration drift assessments and quarterly accuracy determinations shall be done in accordance with Procedure 1 in appendix F to this part, and a data assessment report (DAR), prepared according to section 7 of Procedure 1 in appendix F to this part, shall be submitted with each compliance report required under §60.51Da.

(2) As an alternative to meeting the requirements of paragraph (w)(1) of this section, an owner or operator may elect to implement the following alternative data accuracy assessment procedures. For all required $CO_2$and O_2CEMS and for $SO_2$and NO_XCEMS with span values greater than or equal to 100 ppm, the daily calibration error test and calibration adjustment procedures described in sections 2.1.1 and 2.1.3 of appendix B to part 75 of this chapter may be followed instead of the CD assessment procedures in Procedure 1, section 4.1 of appendix F of this part. If this option is selected, the data validation and out-of-control provisions in sections 2.1.4 and 2.1.5 of appendix B to part 75 of this chapter shall be followed instead of the excessive CD and out-of-control criteria in Procedure 1, section 4.3 of appendix F to this part. For the purposes of data validation under this subpart, the excessive CD and out-of-control criteria in Procedure 1, section 4.3 of appendix F to this part shall apply to $SO_2$and NO_Xspan values less than 100 ppm;

(3) As an alternative to meeting the requirements of paragraph (w)(1) of this section, an owner or operator may elect to may elect to implement the following alternative data accuracy assessment procedures. For all required $CO_2$and O_2CEMS and for $SO_2$and NO_XCEMS with span values greater than 30 ppm, quarterly linearity checks may be performed in accordance with section 2.2.1 of appendix B to part 75 of this chapter, instead of performing the cylinder gas audits (CGAs) described in Procedure 1, section 5.1.2 of appendix F to this part. If this option is selected: The frequency of the linearity checks shall be as specified in section 2.2.1 of appendix B to part 75 of this chapter; the applicable linearity specifications in section 3.2 of appendix A to part 75 of this chapter shall be met; the data validation and out-of-control criteria in section 2.2.3 of appendix B to part 75 of this chapter shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in Procedure 1, section 5.2 of appendix F to this part; and the grace period provisions in section 2.2.4 of appendix B to part 75 of this chapter shall apply. For the purposes of data validation under this subpart, the cylinder gas audits described in Procedure 1, section 5.1.2 of appendix F to this part shall be performed for $SO_2$and NO_Xspan values less than or equal to 30 ppm;

(4) As an alternative to meeting the requirements of paragraph (w)(1) of this section, an owner or operator may elect to may elect to implement the following alternative data accuracy assessment procedures. For SO_2, CO_2, and O_2CEMS and for NO_XCEMS, RATAs may be performed in accordance with section 2.3 of appendix B to part 75 of this chapter instead of following the procedures described in Procedure 1, section 5.1.1 of appendix F

to this part. If this option is selected: The frequency of each RATA shall be as specified in section 2.3.1 of appendix B to part 75 of this chapter; the applicable relative accuracy specifications shown in Figure 2 in appendix B to part 75 of this chapter shall be met; the data validation and out-of-control criteria in section 2.3.2 of appendix B to part 75 of this chapter shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in Procedure 1, section 5.2 of appendix F to this part; and the grace period provisions in section 2.3.3 of appendix B to part 75 of this chapter shall apply. For the purposes of data validation under this subpart, the relative accuracy specification in section 13.2 of Performance Specification 2 in appendix B to this part shall be met on a lb/MMBtu basis for SO_2(regardless of the SO_2emission level during the RATA), and for $NO_X$when the average NO_Xemission rate measured by the reference method during the RATA is less than 0.100 lb/MMBtu;

(5) If the owner or operator elects to implement the alternative data assessment procedures described in paragraphs (w)(2) through (w)(4) of this section, each data assessment report shall include a summary of the results of all of the RATAs, linearity checks, CGAs, and calibration error or drift assessments required by paragraphs (w)(2) through (w)(4) of this section.

[72 FR 32722, June 13, 2007, as amended at 74 FR 5081, Jan. 28, 2009]

§ 60.50Da Compliance determination procedures and methods.

(a) In conducting the performance tests required in §60.8, the owner or operator shall use as reference methods and procedures the methods in appendix A of this part or the methods and procedures as specified in this section, except as provided in §60.8(b). Section 60.8(f) does not apply to this section for $SO_2$and NO_X. Acceptable alternative methods are given in paragraph (e) of this section.

(b) The owner or operator shall determine compliance with the PM standards in §60.42Da as follows:

(1) The dry basis F factor (O_2) procedures in Method 19 of appendix A of this part shall be used to compute the emission rate of PM.

(2) For the particular matter concentration, Method 5 of appendix A of this part shall be used at affected facilities without wet FGD systems and Method 5B of appendix A of this part shall be used after wet FGD systems.

(i) The sampling time and sample volume for each run shall be at least 120 minutes and 1.70 dscm (60 dscf). The probe and filter holder heating system in the sampling train may be set to provide an average gas temperature of no greater than 160±14 °C (320±25 °F).

(ii) For each particulate run, the emission rate correction factor, integrated or grab sampling and analysis procedures of Method 3B of appendix A of this part shall be used to determine the O_2concentration. The O_2sample shall be obtained simultaneously with, and at the same traverse points as, the particulate run. If the particulate run has more than 12 traverse points, the O_2traverse points may be reduced to 12 provided that Method 1 of appendix A of this part is used to locate the 12 O_2traverse points. If the grab sampling procedure is used, the O_2concentration for the run shall be the arithmetic mean of the sample O_2concentrations at all traverse points.

(3) Method 9 of appendix A of this part and the procedures in §60.11 shall be used to determine opacity.

(c) The owner or operator shall determine compliance with the SO_2standards in §60.43Da as follows:

(1) The percent of potential SO_2emissions (%Ps) to the atmosphere shall be computed using the following equation:

$$\%P_s = \frac{(100 - \%R_g)(100 - \%R_g)}{100}$$

Where:

%Ps = Percent of potential SO_2emissions, percent;

%Rf = Percent reduction from fuel pretreatment, percent; and

%Rg = Percent reduction by SO_2control system, percent.

(2) The procedures in Method 19 of appendix A of this part may be used to determine percent reduction ($\%R_f$) of sulfur by such processes as fuel pretreatment (physical coal cleaning, hydrodesulfurization of fuel oil, etc.), coal pulverizers, and bottom and fly ash interactions. This determination is optional.

(3) The procedures in Method 19 of appendix A of this part shall be used to determine the percent SO_2reduction ($\%R_g$) of any SO_2control system. Alternatively, a combination of an "as fired" fuel monitor and emission rates measured after the control system, following the procedures in Method 19 of appendix A of this part, may be used if the percent reduction is calculated using the average emission rate from the SO_2control device and the average SO_2input rate from the "as fired" fuel analysis for 30 successive boiler operating days.

(4) The appropriate procedures in Method 19 of appendix A of this part shall be used to determine the emission rate.

(5) The CEMS in §60.49Da(b) and (d) shall be used to determine the concentrations of $SO_2$and CO_2or O_2.

(d) The owner or operator shall determine compliance with the NO_Xstandard in §60.44Da as follows:

(1) The appropriate procedures in Method 19 of appendix A of this part shall be used to determine the emission rate of NO_X.

(2) The continuous monitoring system in §60.49Da(c) and (d) shall be used to determine the concentrations of $NO_X$and CO_2or O_2.

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

(1) For Method 5 or 5B of appendix A–3 of this part, Method 17 of appendix A–6 of this part may be used at facilities with or without wet FGD systems if the stack temperature at the sampling location does not exceed an average temperature of 160 °C (320 °F). The procedures of sections 8.1 and 11.1 of Method 5B of appendix A–3 of this part may be used in Method 17 of appendix A–6 of this part only if it is used after wet FGD systems. Method 17 of appendix A–6 of this part shall not be used after wet FGD systems if the effluent is saturated or laden with water droplets.

(2) The $F_c$factor (CO_2) procedures in Method 19 of appendix A of this part may be used to compute the emission rate of PM under the stipulations of §60.46(d)(1). The CO_2shall be determined in the same manner as the O_2concentration.

(f) Electric utility combined cycle gas turbines that are not designed to burn fuels containing 50 percent (by heat input) or more solid derived fuel not meeting the definition of natural gas are performance tested for PM, SO_2, and NO_Xusing the procedures of Method 19 of appendix A–7 of this part. The $SO_2$and NO_Xemission rates calculations from the gas turbine used in Method 19 of appendix A–7 of this part are determined when the gas turbine is performance tested under subpart GG of this part. The potential uncontrolled PM emission rate from a gas turbine is defined as 17 ng/J (0.04 lb/MMBtu) heat input.

(g) For the purposes of determining compliance with the emission limits in §60.45Da, the owner or operator of an electric utility steam generating unit which is also a cogeneration unit shall use the procedures in paragraphs (g)(1) and (2) of this section to calculate emission rates based on electrical output to the grid plus 75 percent of the equivalent electrical energy (measured relative to ISO conditions) in the unit's process stream.

DRAFT

(1) All conversions from Btu/hr unit input to MW unit output must use equivalents found in 40 CFR 60.40(a)(1) for electric utilities (*i.e.* , 250 MMBtu/hr input to an electric utility steam generating unit is equivalent to 73 MW input to the electric utility steam generating unit); 73 MW input to the electric utility steam generating unit is equivalent to 25 MW output from the boiler electric utility steam generating unit; therefore, 250 MMBtu input to the electric utility steam generating unit is equivalent to 25 MW output from the electric utility steam generating unit).

(2) Use the Equation 5 in this section to determine the cogeneration Hg emission rate over a specific compliance period.

$$ER_{cogen} = \frac{M}{\left(V_{grid} + 0.75 \times V_{process}\right)} \qquad \text{(Eq. 5)}$$

Where:

ER_{cogen}= Cogeneration Hg emission rate over a compliance period in lb/MWh;

E = Mass of Hg emitted from the stack over the same compliance period (lb);

V_{grid}= Amount of energy sent to the grid over the same compliance period (MWh); and

$V_{process}$= Amount of energy converted to steam for process use over the same compliance period (MWh).

(h) The owner or operator shall determine compliance with the Hg limit in §60.45Da according to the procedures in paragraphs (h)(1) through (3) of this section.

(1) The initial performance test shall be commenced by the applicable date specified in §60.8(a). The required CEMS must be certified prior to commencing the test. The performance test consists of collecting hourly Hg emission data (lb/MWh) with the CEMS for 12 successive months of unit operation (excluding hours of unit startup, shutdown and malfunction). The average Hg emission rate is calculated for each month, and then the weighted, 12-month average Hg emission rate is calculated according to paragraph (h)(2) or (h)(3) of this section, as applicable. If, for any month in the initial performance test, the minimum data capture requirement in §60.49Da(p)(4)(i) is not met, the owner or operator shall report a substitute Hg emission rate for that month, as follows. For the first such month, the substitute monthly Hg emission rate shall be the arithmetic average of all valid hourly Hg emission rates recorded to date. For any subsequent month(s) with insufficient data capture, the substitute monthly Hg emission rate shall be the highest valid hourly Hg emission rate recorded to date. When the 12-month average Hg emission rate for the initial performance test is calculated, for each month in which there was insufficient data capture, the substitute monthly Hg emission rate shall be weighted according to the number of unit operating hours in that month. Following the initial performance test, the owner or operator shall demonstrate compliance by calculating the weighted average of all monthly Hg emission rates (in lb/MWh) for each 12 successive calendar months, excluding data obtained during startup, shutdown, or malfunction.

(2) If a CEMS is used to demonstrate compliance, follow the procedures in paragraphs (h)(2)(i) through (iii) of this section to determine the 12-month rolling average.

(i) Calculate the total mass of Hg emissions over a month (M), in lb, using either Equation 6 in paragraph (h)(2)(i)(A) of this section or Equation 7 in paragraph (h)(2)(i)(B) of this section, in conjunction with Equation 8 in paragraph (h)(2)(i)(C) of this section.

(A) If the Hg CEMS measures Hg concentration on a wet basis, use Equation 6 below to calculate the Hg mass emissions for each valid hour:

$$E_h = KC_h\, Q_h\, t_h \qquad \text{(Eq. 6)}$$

Where:

DRAFT

E_h= Hg mass emissions for the hour, (lb);

K = Units conversion constant, 6.24×10^{-11} lb-scm/µgm-scf;

C_h= Hourly $H_g$concentration, wet basis, (µgm/scm);

Q_h= Hourly stack gas volumetric flow rate, (scfh); and

t_h= Unit operating time, i.e., the fraction of the hour for which the unit operated. For example, th = 0.50 for a half-hour of unit operation and 1.00 for a full hour of operation.

(B) If the Hg CEMS measures Hg concentration on a dry basis, use Equation 7 below to calculate the Hg mass emissions for each valid hour:

$$E_h = KC_h Q_h t_h (1 - B_{ws}) \qquad \text{(Eq. 7)}$$

Where:

E_h= Hg mass emissions for the hour, (lb);

K = Units conversion constant, 6.24×10^{-11}lb-scm/µgm-scf;

C_h= Hourly Hg concentration, dry basis, (µgm/dscm);

Q_h= Hourly stack gas volumetric flow rate, (scfh);

t_h= Unit operating time, *i.e.* , the fraction of the hour for which the unit operated; and

B_{ws}= Stack gas moisture content, expressed as a decimal fraction (*e.g.* , for 8 percent H_2O, B_{ws}= 0.08).

(C) Use Equation 8, below, to calculate M, the total mass of Hg emitted for the month, by summing the hourly masses derived from Equation 6 or 7 (as applicable):

$$M = \sum_{h=1}^{n} E_h \qquad \text{(Eq. 8)}$$

Where:

M = Total Hg mass emissions for the month, (lb);

E_h= Hg mass emissions for hour “h”, from Equation 6 or 7 of this section, (lb); and

n = Number of unit operating hours in the month with valid CE and electrical output data, excluding hours of unit startup, shutdown and malfunction.

(ii) Calculate the monthly Hg emission rate on an output basis (lb/MWh) using Equation 9, below. For a cogeneration unit, use Equation 5 in paragraph (g) of this section instead.

$$ER = \frac{M}{P} \qquad \text{(Eq. 9)}$$

Where:

ER = Monthly Hg emission rate, (lb/MWh);

M = Total mass of Hg emissions for the month, from Equation 8, above, (lb); and

P = Total electrical output for the month, for the hours used to calculate M, (MWh).

(iii) Until 12 monthly Hg emission rates have been accumulated, calculate and report only the monthly averages. Then, for each subsequent calendar month, use Equation 10 below to calculate the 12-month rolling average as a weighted average of the Hg emission rate for the current month and the Hg emission rates for the

DRAFT

previous 11 months, with one exception. Calendar months in which the unit does not operate (zero unit operating hours) shall not be included in the 12-month rolling average.

$$E_{avg} = \frac{\sum_{i=1}^{12}(ER_i \times n_i)}{\sum_{i=1}^{12} n_i} \qquad \text{(Eq. 10)}$$

Where:

E_{avg}= Weighted 12-month rolling average Hg emission rate, (lb/MWh);

ER_i= Monthly Hg emission rate, for month "i", (lb/MWh); and

n = Number of unit operating hours in month "i" with valid CEM and electrical output data, excluding hours of unit startup, shutdown, and malfunction.

(3) If a sorbent trap monitoring system is used in lieu of a Hg CEMS, as described in §75.15 of this chapter and in appendix K to part 75 of this chapter, calculate the monthly Hg emission rates using Equations 7 through 9 of this section, except that for a particular pair of sorbent traps, $C_h$in Equation 7 shall be the flow-proportional average Hg concentration measured over the data collection period.

(i) Daily calibration drift (CD) tests and quarterly accuracy determinations shall be performed for Hg CEMS in accordance with Procedure 1 of appendix F to this part. For the CD assessments, you may use either elemental mercury or mercuric chloride (Hg° $HgCl_2$) standards. The four quarterly accuracy determinations shall consist of one RATA and three measurement error (ME) tests using $HgCl_2$standards, as described in section 8.3 of Performance Specification 12–A in appendix B to this part (note: Hg° standards may be used if the Hg monitor does not have a converter). Alternatively, the owner or operator may implement the applicable daily, weekly, quarterly, and annual quality assurance (QA) requirements for Hg CEMS in appendix B to part 75 of this chapter, in lieu of the QA procedures in appendices B and F to this part. Annual RATA of sorbent trap monitoring systems shall be performed in accordance with appendices A and B to part 75 of this chapter, and all other quality assurance requirements specified in appendix K to part 75 of this chapter shall be met for sorbent trap monitoring systems.

[72 FR 32722, June 13, 2007, as amended at 74 FR 5083, Jan. 28, 2009]

§ 60.51Da Reporting requirements.

(a) For SO_2, NO_X, PM, and Hg emissions, the performance test data from the initial and subsequent performance test and from the performance evaluation of the continuous monitors (including the transmissometer) are submitted to the Administrator.

(b) For $SO_2$and $NO_X$the following information is reported to the Administrator for each 24-hour period.

(1) Calendar date.

(2) The average $SO_2$and NO_Xemission rates (ng/J, lb/MMBtu, or lb/MWh) for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the emission standards; and, description of corrective actions taken.

(3) For owners or operators of affected facilities complying with the percent reduction requirement, percent reduction of the potential combustion concentration of $SO_2$for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the standard; and, description of corrective actions taken.

DRAFT

(4) Identification of the boiler operating days for which pollutant or diluent data have not been obtained by an approved method for at least 75 percent of the hours of operation of the facility; justification for not obtaining sufficient data; and description of corrective actions taken.

(5) Identification of the times when emissions data have been excluded from the calculation of average emission rates because of startup, shutdown, malfunction (NO_Xonly), emergency conditions (SO_2only), or other reasons, and justification for excluding data for reasons other than startup, shutdown, malfunction, or emergency conditions.

(6) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted.

(7) Identification of times when hourly averages have been obtained based on manual sampling methods.

(8) Identification of the times when the pollutant concentration exceeded full span of the CEMS.

(9) Description of any modifications to CEMS which could affect the ability of the CEMS to comply with Performance Specifications 2 or 3.

(c) If the minimum quantity of emission data as required by §60.49Da is not obtained for any 30 successive boiler operating days, the following information obtained under the requirements of §60.48Da(h) is reported to the Administrator for that 30-day period:

(1) The number of hourly averages available for outlet emission rates (no) and inlet emission rates (n_i) as applicable.

(2) The standard deviation of hourly averages for outlet emission rates (s_o) and inlet emission rates (s_i) as applicable.

(3) The lower confidence limit for the mean outlet emission rate (E_o*) and the upper confidence limit for the mean inlet emission rate (E_i*) as applicable.

(4) The applicable potential combustion concentration.

(5) The ratio of the upper confidence limit for the mean outlet emission rate (E_o*) and the allowable emission rate (E_{std}) as applicable.

(d) If any standards under §60.43Da are exceeded during emergency conditions because of control system malfunction, the owner or operator of the affected facility shall submit a signed statement:

(1) Indicating if emergency conditions existed and requirements under §60.48Da(d) were met during each period, and

(2) Listing the following information:

(i) Time periods the emergency condition existed;

(ii) Electrical output and demand on the owner or operator's electric utility system and the affected facility;

(iii) Amount of power purchased from interconnected neighboring utility companies during the emergency period;

(iv) Percent reduction in emissions achieved;

(v) Atmospheric emission rate (ng/J) of the pollutant discharged; and

(vi) Actions taken to correct control system malfunction.

(e) If fuel pretreatment credit toward the SO_2emission standard under §60.43Da is claimed, the owner or operator of the affected facility shall submit a signed statement:

DRAFT

(1) Indicating what percentage cleaning credit was taken for the calendar quarter, and whether the credit was determined in accordance with the provisions of §60.50Da and Method 19 of appendix A of this part; and

(2) Listing the quantity, heat content, and date each pretreated fuel shipment was received during the previous quarter; the name and location of the fuel pretreatment facility; and the total quantity and total heat content of all fuels received at the affected facility during the previous quarter.

(f) For any periods for which opacity, SO_2or NO_Xemissions data are not available, the owner or operator of the affected facility shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.

(g) For Hg, the following information shall be reported to the Administrator:

(1) Company name and address;

(2) Date of report and beginning and ending dates of the reporting period;

(3) The applicable Hg emission limit (lb/MWh); and

(4) For each month in the reporting period:

(i) The number of unit operating hours;

(ii) The number of unit operating hours with valid data for Hg concentration, stack gas flow rate, moisture (if required), and electrical output;

(iii) The monthly Hg emission rate (lb/MWh);

(iv) The number of hours of valid data excluded from the calculation of the monthly Hg emission rate, due to unit startup, shutdown and malfunction; and

(v) The 12-month rolling average Hg emission rate (lb/MWh); and

(5) The data assessment report (DAR) required by appendix F to this part, or an equivalent summary of QA test results if the QA of part 75 of this chapter are implemented.

(h) The owner or operator of the affected facility shall submit a signed statement indicating whether:

(1) The required CEMS calibration, span, and drift checks or other periodic audits have or have not been performed as specified.

(2) The data used to show compliance was or was not obtained in accordance with approved methods and procedures of this part and is representative of plant performance.

(3) The minimum data requirements have or have not been met; or, the minimum data requirements have not been met for errors that were unavoidable.

(4) Compliance with the standards has or has not been achieved during the reporting period.

(i) For the purposes of the reports required under §60.7, periods of excess emissions are defined as all 6-minute periods during which the average opacity exceeds the applicable opacity standards under §60.42Da(b). Opacity levels in excess of the applicable opacity standard and the date of such excesses are to be submitted to the Administrator each calendar quarter.

(j) The owner or operator of an affected facility shall submit the written reports required under this section and subpart A to the Administrator semiannually for each six-month period. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period.

DRAFT

(k) The owner or operator of an affected facility may submit electronic quarterly reports for $SO_2$and/or $NO_X$and/or opacity and/or Hg in lieu of submitting the written reports required under paragraphs (b), (g), and (i) of this section. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format.

[72 FR 32722, June 13, 2007, as amended at 74 FR 5083, Jan. 28, 2009]

§ 60.52Da Recordkeeping requirements.

(a) The owner or operator of an affected facility subject to the emissions limitations in §60.45Da shall provide notifications in accordance with §60.7(a) and shall maintain records of all information needed to demonstrate compliance including performance tests, monitoring data, fuel analyses, and calculations, consistent with the requirements of §60.7(f).

(b) The owner or operator of an affected facility subject to the opacity limits in §60.42Da(b) that elects to monitor emissions according to the requirements in §60.49Da(a)(3) shall maintain records according to the requirements specified in paragraphs (b)(1) through (3) of this section, as applicable to the visible emissions monitoring method used.

(1) For each performance test conducted using Method 9 of appendix A–4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (b)(1)(i) through (iii) of this section.

(i) Dates and time intervals of all opacity observation periods;

(ii) Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test; and

(iii) Copies of all visible emission observer opacity field data sheets;

(2) For each performance test conducted using Method 22 of appendix A–4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (b)(2)(i) through (iv) of this section.

(i) Dates and time intervals of all visible emissions observation periods;

(ii) Name and affiliation for each visible emission observer participating in the performance test;

(iii) Copies of all visible emission observer opacity field data sheets; and

(iv) Documentation of any adjustments made and the time the adjustments were completed to the affected facility operation by the owner or operator to demonstrate compliance with the applicable monitoring requirements.

(3) For each digital opacity compliance system, the owner or operator shall maintain records and submit reports according to the requirements specified in the site-specific monitoring plan approved by the Administrator.

[74 FR 5083, Jan. 28, 2009]

Link to 40 CFR 60, Subpart Da

DRAFT

40 CFR 75, APPENDIX F, SECTION 5 – MEASUREMENT OF BOILER HEAT INPUT RATE

{Permitting Note: This is the section (Section 5) of Appendix F of 40 CFR 75 including the F-Factor Table for fuels that deals with the calculation of the heat input rate to a steam generating boiler. This procedure is utilized by boilers that fall under the Acid Rain program. This is the procedure that GREC will utilize to calculate the heat input rate to the BFB biomass boiler. To access the full version of 40 CFR 75, Appendix F, follow the link at the end of this appendix.}

5. Procedures for Heat Input

Use the following procedures to compute heat input rate to an affected unit (in mmBtu/hr or mmBtu/day):

5.1 Calculate and record heat input rate to an affected unit on an hourly basis, except as provided in sections 5.5 through 5.5.7. The owner or operator may choose to use the provisions specified in §75.16(e) or in section 2.1.2 of appendix D to this part in conjunction with the procedures provided in sections 5.6 through 5.6.2 to apportion heat input among each unit using the common stack or common pipe header.

5.2 For an affected unit that has a flow monitor (or approved alternate monitoring system under subpart E of this part for measuring volumetric flow rate) and a diluent gas (O_2or CO_2) monitor, use the recorded data from these monitors and one of the following equations to calculate hourly heat input rate (in mmBtu/hr).

5.2.1 When measurements of CO_2concentration are on a wet basis, use the following equation:

$$HI = Q_w \frac{1}{F_c} \frac{\%CO_{2w}}{100} \qquad (Eq.\ F\text{-}15)$$

Where:

HI = Hourly heat input rate during unit operation, mmBtu/hr.

Q_w= Hourly average volumetric flow rate during unit operation, wet basis, scfh.

F_c= Carbon-based F-factor, listed in section 3.3.5 of this appendix for each fuel, scf/mmBtu.

$\%CO_{2w}$= Hourly concentration of CO_2during unit operation, percent CO_2wet basis.

5.2.2 When measurements of CO_2concentration are on a dry basis, use the following equation:

$$HI = Q_h \left[\frac{(100 - \%H_2O)}{100F_c}\right]\left(\frac{\%CO_{2d}}{100}\right) \qquad (Eq.\ F\text{-}16)$$

Where:

HI = Hourly heat input rate during unit operation, mmBtu/hr.

Q_h= Hourly average volumetric flow rate during unit operation, wet basis, scfh.

F_c= Carbon-based F-Factor, listed in section 3.3.5 of this appendix for each fuel, scf/mmBtu.

$\%CO_{2d}$= Hourly concentration of CO_2during unit operation, percent CO_2dry basis.

$\%H_2O$ = Moisture content of gas in the stack, percent.

5.2.3 When measurements of O_2concentration are on a wet basis, use the following equation:

$$HI = Q_w \frac{1}{F} \frac{\left[(20.9/100)(100 - \%H_2O) - \%O_{2w}\right]}{20.9} \qquad (Eq.\ F\text{-}17)$$

Where:

DRAFT

HI = Hourly heat input rate during unit operation, mmBtu/hr.

Q_w= Hourly average volumetric flow rate during unit operation, wet basis, scfh.

F = Dry basis F-factor, listed in section 3.3.5 of this appendix for each fuel, dscf/mmBtu.

$\%O_{2w}$= Hourly concentration of O_2during unit operation, percent O_2wet basis. For any operating hour where Equation F–17 results in an hourly heat input rate that is ≤ 0.0 mmBtu/hr, 1.0 mmBtu/hr shall be recorded and reported as the heat input rate for that hour.

$\%H_2O$ = Hourly average stack moisture content, percent by volume.

5.2.4 When measurements of O_2concentration are on a dry basis, use the following equation:

$$HI = Q_w \left[\frac{(100 - \%H_2O)}{100\ F}\right]\left[\frac{(20.9 - \%O_{2d})}{20.9}\right] \qquad (Eq.\ F\text{-}18)$$

Where:

HI = Hourly heat input rate during unit operation, mmBtu/hr.

Q_w= Hourly average volumetric flow during unit operation, wet basis, scfh.

F = Dry basis F-factor, listed in Table 1 at the end of this of this appendix for each fuel, dscf/mmBtu.

$\%H_2O$ = Moisture content of the stack gas, percent.

$\%O_{2d}$= Hourly concentration of O_2during unit operation, percent O_2dry basis.

5.3 Heat Input Summation (for Heat Input Determined Using a Flow Monitor and Diluent Monitor)

5.3.1 Calculate total quarterly heat input for a unit or common stack using a flow monitor and diluent monitor to calculate heat input, using the following equation:

$$HI_q = \sum_{hour=1}^{n} HI_i t_i \qquad (Eq.\ F\text{-}18a)$$

Where:

HI_q= Total heat input for the quarter, mmBtu.

HI_i= Hourly heat input rate during unit operation, using Equation F–15, F–16, F–17, or F–18, mmBtu/hr.

t_i= Hourly operating time for the unit or common stack, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

5.3.2 Calculate total cumulative heat input for a unit or common stack using a flow monitor and diluent monitor to calculate heat input, using the following equation:

$$HI_c = \sum_{q=1}^{\text{the current quarter}} HI_q \qquad (Eq.\ F\text{-}18b)$$

Where:

HI_c= Total heat input for the year to date, mmBtu.

HI_q= Total heat input for the quarter, mmBtu.

DRAFT

5.4 [Reserved]

5.5 For a gas-fired or oil-fired unit that does not have a flow monitor and is using the procedures specified in appendix D to this part to monitor SO_2emissions or for any unit using a common stack for which the owner or operator chooses to determine heat input by fuel sampling and analysis, use the following procedures to calculate hourly heat input rate in mmBtu/hr. The procedures of section 5.5.3 of this appendix shall not be used to determine heat input from a coal unit that is required to comply with the provisions of this part for monitoring, recording, and reporting NO_X mass emissions under a State or federal NO_X mass emission reduction program.

5.5.1 (a) When the unit is combusting oil, use the following equation to calculate hourly heat input rate:

$$HI_o = M_o \frac{GCV_o}{10^6} \qquad (Eq.\ F\text{-}19)$$

Where:

HI_o= Hourly heat input rate from oil, mmBtu/hr.

M_o= Mass rate of oil consumed per hour, as determined using procedures in appendix D to this part, in lb/hr, tons/hr, or kg/hr.

GCV_o= Gross calorific value of oil, as measured by ASTM D240–00, ASTM D5865–01a, or ASTM D4809–00 for each oil sample under section 2.2 of appendix D to this part, Btu/unit mass (all incorporated by reference under (§75.6 of this part).

10^6 = Conversion of Btu to mmBtu.

(b) When performing oil sampling and analysis solely for the purpose of the missing data procedures in §75.36, oil samples for measuring GCV may be taken weekly, and the procedures specified in appendix D to this part for determining the mass rate of oil consumed per hour are optional.

5.5.2 When the unit is combusting gaseous fuels, use the following equation to calculate heat input rate from gaseous fuels for each hour:

$$HI_g = \frac{(Q_g \times GCV_g)}{10^6} \qquad (Eq.\ F\text{-}20)$$

Where:

HI_g= Hourly heat input rate from gaseous fuel, mmBtu/hour.

Q_g= Metered flow rate of gaseous fuel combusted during unit operation, hundred standard cubic feet per hour.

GCV_g= Gross calorific value of gaseous fuel, as determined by sampling (for each delivery for gaseous fuel in lots, for each daily gas sample for gaseous fuel delivered by pipeline, for each hourly average for gas measured hourly with a gas chromatograph, or for each monthly sample of pipeline natural gas, or as verified by the contractual supplier at least once every month pipeline natural gas is combusted, as specified in section 2.3 of appendix D to this part) using ASTM D1826–94 (Reapproved 1998), ASTM D3588–98, ASTM D4891–89 (Reapproved 2006), GPA Standard 2172–96 Calculation of Gross Heating Value, Relative Density and Compressibility Factor for Natural Gas Mixtures from Compositional Analysis, or GPA Standard 2261–00 Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography, Btu/100 scf (all incorporated by reference under §75.6 of this part).

10^6 = Conversion of Btu to mmBtu.

DRAFT

5.5.3 When the unit is combusting coal, use the procedures, methods, and equations in sections 5.5.3.1–5.5.3.3 of this appendix to determine the heat input from coal for each 24-hour period. (All ASTM methods are incorporated by reference under §75.6 of this part.)

5.5.3.1 Perform coal sampling daily according to section 5.3.2.2 in Method 19 in appendix A to part 60 of this chapter and use ASTM D2234–00, Standard Practice for Collection of a Gross Sample of Coal, (incorporated by reference under §75.6 of this part) Type I, Conditions A, B, or C and systematic spacing for sampling. (When performing coal sampling solely for the purposes of the missing data procedures in §75.36, use of ASTM D2234–00 is optional, and coal samples may be taken weekly.)

5.5.3.2 All ASTM methods are incorporated by reference under §75.6 of this part. Use ASTM D2013–01, Standard Practice for Preparing Coal Samples for Analysis, for preparation of a daily coal sample and analyze each daily coal sample for gross calorific value using ASTM D5865–01a, Standard Test Method for Gross Calorific Value of Coal and Coke. On-line coal analysis may also be used if the on-line analytical instrument has been demonstrated to be equivalent to the applicable ASTM methods under §§75.23 and 75.66.

5.5.3.3 Calculate the heat input from coal using the following equation:

$$HI_c = M_c \frac{GCV_c}{500} \qquad (Eq.\ F\text{-}21)$$

(Eq. F–21)

where:

HIc = Daily heat input from coal, mmBtu/day.

Mc = Mass of coal consumed per day, as measured and recorded in company records, tons.

GCV_c= Gross calorific value of coal sample, as measured by ASTM D3176–89 (Reapproved 2002), or ASTM D5865–01a, Btu/lb. (incorporated by reference under §75.6 of this part).

500 = Conversion of Btu/lb to mmBtu/ton.

5.5.4 For units obtaining heat input values daily instead of hourly, apportion the daily heat input using the fraction of the daily steam load or daily unit operating load used each hour in order to obtain HI_i for use in the above equations. Alternatively, use the hourly mass of coal consumed in equation F–21.

5.5.5 If a daily fuel sampling value for gross calorific value is not available, substitute the maximum gross calorific value measured from the previous 30 daily samples. If a monthly fuel sampling value for gross calorific value is not available, substitute the maximum gross calorific value measured from the previous 3 monthly samples.

5.5.6 If a fuel flow value is not available, use the fuel flowmeter missing data procedures in section 2.4 of appendix D of this part. If a daily coal consumption value is not available, substitute the maximum fuel feed rate during the previous thirty days when the unit burned coal.

5.5.7 Results for samples must be available no later than thirty calendar days after the sample is composited or taken. However, during an audit, the Administrator may require that the results be available in five business days, or sooner if practicable.

5.6 Heat Input Rate Apportionment for Units Sharing a Common Stack or Pipe

DRAFT

5.6.1 Where applicable, the owner or operator of an affected unit that determines heat input rate at the unit level by apportioning the heat input monitored at a common stack or common pipe using megawatts shall apportion the heat input rate using the following equation:

$$HI_i = HI_{CS}\left(\frac{t_{CS}}{t_i}\right)\left[\frac{MW_i t_i}{\sum_{i=1}^{n} MW_i t_i}\right] \qquad (Eq.\ \text{F-21a})$$

Where:

HI_i= Heat input rate for a unit, mmBtu/hr.

HI_{cs}= Heat input rate at the common stack or pipe, mmBtu/hr.

MW_i= Gross electrical output, MWe.

t_i= Unit operating time, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

t_{CS}= Common stack or common pipe operating time, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

n = Total number of units using the common stack or pipe.

i = Designation of a particular unit.

5.6.2 Where applicable, the owner or operator of an affected unit that determines the heat input rate at the unit level by apportioning the heat input rate monitored at a common stack or common pipe using steam load shall apportion the heat input rate using the following equation:

$$HI_i = HI_{CS}\left(\frac{t_{CS}}{t_i}\right)\left[\frac{SF_i t_i}{\sum_{i=1}^{n} SF_i t_i}\right] \qquad (Eq.\ \text{F-21b})$$

Where:

HI_i= Heat input rate for a unit, mmBtu/hr.

HI_{CS}= Heat input rate at the common stack or pipe, mmBtu/hr.

SF = Gross steam load, lb/hr, or mmBtu/hr.

t_i= Unit operating time, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

t_{CS}= Common stack or common pipe operating time, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

n = Total number of units using the common stack or pipe.

i = Designation of a particular unit.

5.7 Heat Input Rate Summation for Units with Multiple Stacks or Pipes

DRAFT

40 CFR 75, APPENDIX F, SECTION 5 – MEASUREMENT OF BOILER HEAT INPUT RATE

The owner or operator of an affected unit that determines the heat input rate at the unit level by summing the heat input rates monitored at multiple stacks or multiple pipes shall sum the heat input rates using the following equation:

$$HI_{Unit} = \frac{\sum_{s=1}^{n} HI_s t_s}{t_{Unit}} \qquad (Eq.\ \text{F-21c})$$

Where:

HI_{Unit}= Heat input rate for a unit, mmBtu/hr.

HI_s= Heat input rate for the individual stack, duct, or pipe, mmBtu/hr.

t_{Unit}= Unit operating time, hour or fraction of the hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

t_s= Operating time for the individual stack or pipe, hour or fraction of the hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

s = Designation for a particular stack, duct, or pipe.

5.8 Alternate Heat Input Apportionment for Common Pipes

As an alternative to using Equation F–21a or F–21b in section 5.6 of this appendix, the owner or operator may apportion the heat input rate at a common pipe to the individual units served by the common pipe based on the fuel flow rate to the individual units, as measured by uncertified fuel flowmeters. This option may only be used if a fuel flowmeter system that meets the requirements of appendix D to this part is installed on the common pipe. If this option is used, determine the unit heat input rates using the following equation:

$$HI_i = HI_{CP}\left(\frac{t_{CP}}{t_i}\right)\left[\frac{FF_i t_i}{\sum_{i=1}^{n} FF_i t_i}\right] \qquad (Eq.\ \text{F-21}d)$$

Where:

HI_i= Heat input rate for a unit, mmBtu/hr.

HI_{CP}= Heat input rate at the common pipe, mmBtu/hr.

FF_i= Fuel flow rate to a unit, gal/min, 100 scfh, or other appropriate units.

t_i= Unit operating time, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

t_{CP}= Common pipe operating time, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

n = Total number of units using the common pipe.

i = Designation of a particular unit.

DRAFT

3.3.5 F, F_c=a factor representing a ratio of the volume of dry flue gases generated to the caloric value of the fuel combusted (F), and a factor representing a ratio of the volume of CO_2generated to the calorific value of the fuel combusted (F_c), respectively. Table 1 lists the values of F and F_c for different fuels. The permittee at their discretion may use the procedure of 40 CFR Part 75, Appendix F, Section 3.3.6 to calculate a site specific F factor for the BFB biomass boiler at the GREC facility.

Table 1—F- and F_c-Factors[1]

Fuel	F-factor (dscf/mmBtu)	F_C-factor (scf CO_2/mmBtu)
Coal (as defined by ASTM D388–99[2]):		
Anthracite	10,100	1,970
Bituminous	9,780	1,800
Subbituminous	9,820	1,840
Lignite	9,860	1,910
Petroleum Coke	9,830	1,850
Tire Derived Fuel	10,260	1,800
Oil	9,190	1,420
Gas:		
Natural gas	8,710	1,040
Propane	8,710	1,190
Butane	8,710	1,250
Wood:		
Bark	9,600	1,920
Wood residue	9,240	1,830

[1]Determined at standard conditions: 20 °C (68 °F) and 29.92 inches of mercury.
[2]Incorporated by reference under §75.6 of this part.

Link to 40 CFR 75, Appendix F

DRAFT

GENERAL CONDITIONS

The permittee shall comply with the following general conditions from Rule 62-4.160, F.A.C.

1. The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.
2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.
3. As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey and vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.
4. This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.
5. This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.
6. The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.
7. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:
   a. Have access to and copy and records that must be kept under the conditions of the permit;
   b. Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,
   c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

   Reasonable time may depend on the nature of the concern being investigated.
8. If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:
   a. A description of and cause of non-compliance; and
   b. The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

   The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

DRAFT

9. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, Florida Statutes. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

10. The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.

11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

12. This permit or a copy thereof shall be kept at the work site of the permitted activity.

13. This permit also constitutes:

    a. Determination of Best Available Control Technology ( );
    b. Determination of Prevention of Significant Deterioration ( );
    c. Compliance with National Emission Standards for Hazardous Air Pollutants ( ); and
    d. Compliance with New Source Performance Standards (X).

14. The permittee shall comply with the following:

    a. Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.

    b. The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application or this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.

    c. Records of monitoring information shall include:

        1) The date, exact place, and time of sampling or measurements;
        2) The person responsible for performing the sampling or measurements;
        3) The dates analyses were performed;
        4) The person responsible for performing the analyses;
        5) The analytical techniques or methods used; and
        6) The results of such analyses.

15. When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

.

DRAFT

NSPS - SUBPART A, IDENTIFICATION OF GENERAL PROVISIONS

The provisions of this Subpart may be provided in full upon request. Emissions units subject to a New Source Performance Standard of 40 CFR 60 are also subject to the applicable requirements of Subpart A, the General Provisions, including:

§ 60.1 Applicability.

§ 60.2 Definitions.

§ 60.3 Units and abbreviations.

§ 60.4 Address.

§ 60.5 Determination of construction or modification.

§ 60.6 Review of plans.

§ 60.7 Notification and Record Keeping.

§ 60.8 Performance Tests.

§ 60.9 Availability of information.

§ 60.10 State Authority.

§ 60.11 Compliance with Standards and Maintenance Requirements.

§ 60.12 Circumvention.

§ 60.13 Monitoring Requirements.

§ 60.14 Modification.

§ 60.15 Reconstruction.

§ 60.16 Priority List.

§ 60.17 Incorporations by Reference.

§ 60.18 General Control Device Requirements.

§ 60.19 General Notification and Reporting Requirements.

Individual subparts may exempt specific equipment or processes from some or all of these requirements. The general provisions may be provided in full upon request.

NESHAP - SUBPART A, IDENTIFICATION OF GENERAL PROVISIONS

The provisions of this Subpart may be provided in full upon request. Emissions units subject to a National Emission Standards for Hazardous Air Pollutants of 40 CFR 63 are also subject to the applicable requirements of Subpart A, the General Provisions, including:

§ 63.1 Applicability.

§ 63.2 Definitions.

§ 63.3 Units and abbreviations.

§ 63.4 Prohibited Activities and Circumvention.

§ 63.5 Preconstruction Review and Notification Requirements.

§ 63.6 Compliance with Standards and Maintenance Requirements.

§ 63.7 Performance Testing Requirements.

DRAFT

§ 63.8 Monitoring Requirements.

§ 63.9 Notification Requirements.

§ 63.10 Recordkeeping and Reporting Requirements.

§ 63.11 Control Device Requirements.

§ 63.12 State Authority and Delegations.

§ 63.13 Addresses of State Air Pollution Control Agencies and EPA Regional Offices.

§ 63.14 Incorporation by Reference.

§ 63.15 Availability of Information and Confidentiality.

Individual subparts may exempt specific equipment or processes from some or all of these requirements. The general provisions may be provided in full upon request.

DRAFT

NSPS, SUBPART IIII - STATIONARY COMPRESSION IGNITION INTERNAL COMBUSTION ENGINES

A 1800 kW or less emergency generator (EU ID 004) and two 500 hp or less water pumps (EU-005 and EU-006) are proposed for the GREC facility and they are subject to the applicable requirements of 40 CFR 60, Subpart IIII--Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. The provisions of this Subpart may be provided in full upon request and are also available at the following link:

Link to Subpart IIII

DRAFT

NESHAP, SUBPART ZZZZ – STATIONARY RECIPROCATING INTERNAL COMBUSTION ENGINES

A 1800 kW or less emergency generator (EU ID 004) and two 500 hp or less water pumps (EU-005 and EU-006) are proposed for the GREC facility and they are subject to the requirements of 40 CFR 63, Subpart ZZZZ--National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines. The complete provisions of Subpart ZZZZ may be provided in full upon request and are also available beginning at Section 63.6580 at:

Link to Subpart ZZZZ

DRAFT