TITLE 45
LEGISLATIVE RULE
DEPARTMENT OF ENVIRONMENTAL PROTECTION
AIR QUALITY

SERIES 40
CONTROL OF OZONE SEASON NITROGEN OXIDES EMISSIONS

§45-40-1. General.

1.1. Scope. -- This rule establishes:

1.1.a. Ozone season NO_X emission limitation, monitoring, recordkeeping, reporting, excess emissions, and NO_X budget demonstration requirements for large industrial boilers and combustion turbines that have a maximum design heat input greater than 250 mmBTU/hr, in accordance with 40 CFR §51.121;

1.1.b Ozone season NO_X reduction, compliance plan, monitoring, recordkeeping and reporting requirements for affected stationary internal combustion engines; and

1.1.c. Ozone season NO_X control standards, ozone season NO_X compliance plan, reporting, monitoring and recordkeeping requirements for applicable cement manufacturing kilns.

1.2. Authority. -- W.Va. Code §22-5-4.

1.3. Filing Date. -- ~~June 16, 2016~~.

1.4. Effective Date. -- ~~July 1, 2016~~.

1.5. ~~Former Rules. -- This legislative rule amends 45CSR40 - "Control of Ozone Season Nitrogen Oxide Emissions" which was filed April 14, 2008, and which became effective May 1, 2008~~. Sunset Provision. -- Exempt.

§45-40-2. Definitions.

2.1. "Administrator" means the Administrator of the United States Environmental Protection Agency (U.S. EPA) or the Administrator's duly authorized representative.

2.2. "Boiler" means an enclosed fossil or other fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

2.3. "Clean Air Act" or "CAA" means the Clean Air Act, 42 U.S.C. 7401, et seq., as amended.

2.4. "Clinker" means the product of a Portland cement kiln from which finished cement is manufactured by milling and grinding.

2.5. "Combustion turbine" means:

2.5.a. An enclosed device comprising a compressor, a combustor, and a turbine and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine; and

2.5.b. If the enclosed device under subdivision 2.6.a is combined cycle, any associated duct burner, heat recovery steam generator, and steam turbine.

2.6. "Continuous emission monitoring system" or "CEMS" means, except for purposes of subsections 2.15 and 6.2, the ~~equipment required under 40 CFR part 75, subpart H to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes (using an automated data acquisition and handling system (DAHS)), a permanent record of nitrogen oxides emissions, expressed in tons per hour for nitrogen oxides, stack gas volumetric flow rate, stack gas moisture content, and oxygen (O_2) or carbon dioxide (CO_2)concentration (as applicable), in a manner consistent with 40 CFR part 75~~ total equipment required for the determination of NO_X emission rate, expressed in pounds per million British thermal units (lb/mmBtu). For the purposes of this rule, CEMS is used for continuous compliance determinations. The sample interface, pollutant analyzer, diluent analyzer, and data recorder are the major subsystems of the CEMS. ~~The following systems are t~~The principal ~~types~~ type of continuous emission monitoring ~~systems~~ system is:

2.6.a. ~~A flow monitoring system, consisting of a stack flow rate monitor and an automated data acquisition and handling system and providing a permanent, continuous record of stack gas volumetric flow rate, in standard cubic feet per hour (scfh);~~

~~2.6.b. A nitrogen oxides concentration monitoring system, consisting of a NO_X pollutant concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of NO_X emissions, in parts per million (ppm);~~

~~2.6.c.~~ A nitrogen oxides emission rate (or NO_X-diluent) monitoring system, consisting of a NO_X pollutant concentration monitor, a diluent gas (CO_2 or O_2) monitor, and an automated data acquisition and handling system and providing a permanent, continuous record of NO_X concentration, in parts per million (ppm), diluent gas concentration, in percent CO_2 or O_2; and NO_X emission rate, in pounds per million British thermal units (lb/mmBtu);

~~2.6.d. A moisture monitoring system, as defined in 40 CFR §75.11(b)(2) and providing a permanent, continuous record of the stack gas moisture content, in percent H_2O;~~

~~2.6.e. A carbon dioxide monitoring system, consisting of a CO_2 pollutant concentration monitor (or an oxygen monitor plus suitable mathematical equations from which the CO_2 concentration is derived) and an automated data acquisition and handling system and providing a permanent, continuous record of CO_2 emissions, in percent CO_2; and~~

~~2.6.f. An oxygen monitoring system, consisting of an O_2 concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of O_2, in percent O_2~~.

2.7. "Excess emissions" means nitrogen oxides emitted by an applicable unit under subsection 4.1 during an ozone season that exceeds the ozone season NO_X emissions limitation for the unit set forth in section 5.

2.8. "Fossil fuel" means natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material.

2.9. "Fossil fuel-fired" means, with regard to a unit, and solely for purposes of applying the applicability provisions in subsection 4.1:

2.9.a. The combustion of fossil fuel, alone or in combination with any other fuel, where fossil fuel actually combusted comprises more than 50 percent of the annual heat input on a Btu basis during any year; or

2.9.b. The combustion of fossil fuel, alone or in combination with any other fuel, where fossil fuel is projected to comprise more than 50 percent of the annual heat input on a Btu basis during any year; provided that the unit shall be "fossil fuel-fired" as of the date, during such year, on which the unit begins combusting fossil fuel.

2.10. "Large NO_X SIP call engine" means a stationary internal combustion engine identified and designated as "large" in the NO_X SIP Call Engine Inventory as emitting more than one ton of NO_X per average ozone season day in 1995.

2.11. "Long dry kiln" means a kiln 14 feet or larger in diameter, 400 feet or greater in length, which employs no preheating of the feed. The inlet feed to the kiln is dry.

2.12. "Long wet kiln" means a kiln 14 feet or larger in diameter, 400 feet or greater in length, which employs no preheating of the feed. The inlet feed to the kiln is a slurry.

2.13. "Low-NO_X burners" means combustion equipment designed to reduce flame turbulence, delay fuel/air mixing and establish fuel-rich zones for initial combustion.

2.14. "Mid-kiln firing" means the secondary firing in kilns by injecting solid fuel at an intermediate point in the kiln using a specially designed feed injection mechanism for the purpose of decreasing NO_X emissions through:

2.14.a. Burning part of the fuel at a lower temperature; and

2.14.b. Reducing conditions at the solid waste injection point that may destroy some of the NO_X formed upstream in the kiln burning zone.

2.15. "Monitoring system" means, for purposes of subsection 6.2, a continuous emissions monitoring system, an alternative monitoring system, or an excepted monitoring system under 40 CFR part 75 as defined in 40 CFR §72.2.

2.16. "Nitrogen oxides" or "NO_X" means all oxides of nitrogen except nitrous oxide (N_2O), reported on an equivalent molecular weight basis as nitrogen dioxide (NO_2).

~~2.16~~ 2.17. "NO_X SIP Call Engine Inventory" means the inventory of internal combustion engines compiled by U.S. EPA as part of the NO_X SIP Call Rule, including the technical amendments, announced in the March 2, 2000 ~~FR~~ Federal Register, page 11222, and the adjustment of the 2007 Budget NO_X Control Efficiency to 82 percent for large gas-fired engines, announced in the April 21, 2004 Federal Register notice, page 21604 for the Phase II NO_X SIP Call Rule.

~~2.17~~ 2.18. "Ozone season" means the period beginning May 1 of a calendar year, and ending on September 30 of the same year, inclusive.

2.19. "Performance Specification 2" or "PS 2" means the Specifications and Test Procedures for SO_2 and NO_X Continuous Emission Monitoring Systems in Stationary Sources provided in Appendix B to 40 CFR part 60. For purposes of subsections 6.3 and 6.5, these procedures are used for measuring CEMS relative accuracy and calibration drift and include CEMS installation and measurement location specifications, equipment specifications, performance specifications, and data reduction.

2.20. "Performance Specification 16" or "PS 16" means the Specifications and Test Procedures for Predictive Emission Monitoring Systems (PEMS) in Stationary Sources provided in Appendix B to 40 CFR part 60. For purposes of subsection 6.4, these procedures are used to determine whether the PEMS is acceptable for use in demonstrating compliance with the NO_X emission limit and to certify the PEMS initially. They are also used periodically thereafter to ensure the PEMS is operating properly. These specifications apply to PEMS that are installed on or after April 24, 2009.

2.21. "Predictive Emission Monitoring System" or "PEMS" means all of the equipment required to predict an emission concentration or emission rate. The system may consist of any of the following major subsystems: sensors and sensor interfaces, emission model, algorithm, or equation that uses process data to generate an output that is proportional to the emission concentration or emission rate, diluent emission model, data recorder, and sensor evaluation system. Systems that use fewer than three (3) variables do not qualify as PEMS unless the system has been specifically approved by the Administrator for use as a PEMS. A PEMS may predict emissions data that are corrected for diluent if the relative accuracy and relevant QA tests are passed in the emission units corrected for diluent. Parametric monitoring systems that serve as indicators of compliance and have parametric limits but do not predict emissions to comply with an emissions limit are not included in this definition.

~~2.18~~ 2.22. "Portland cement" means a hydraulic cement produced by pulverizing clinker consisting essentially of hydraulic calcium silicates, usually containing one or more of the forms of calcium sulfate as an interground addition.

~~2.19~~ 2.23. "Portland cement kiln" means a system, including any solid, gaseous or liquid fuel combustion equipment, used to calcine and fuse raw materials, including limestone and clay, to produce Portland cement clinker

~~2.20~~ 2.24. "Precalciner kiln" means a kiln where the feed to the kiln system is preheated in cyclone chambers and utilizes a second burner to calcine material in a separate vessel attached to the preheater prior to the final fusion in a kiln which forms clinker.

~~2.21~~ 2.25. "Preheater kiln" means a kiln where the feed to the kiln system is preheated in cyclone chambers prior to the final fusion in a kiln which forms clinker.

~~2.22~~ 2.26. "Secretary" means the Secretary of the Department of Environmental Protection or such other person to whom the Secretary has delegated authority or duties pursuant to W.Va. Code §§22-1-6 or 22-1-8.

~~2.23~~ 2.27. "Source" means all buildings, structures, or installations located in one or more contiguous or adjacent properties under common control of the same person or persons.

~~2.24~~ 2.28. "Stationary internal combustion engine" or "engine" means any internal combustion engine of the reciprocating type that is either attached to a foundation at a facility or is designed to be capable of being carried or moved from one location to another and remains at a single site at a building, structure, facility, or installation for more than 12 consecutive months. Any engine (or engines) that replaces an engine at a site that is intended to perform the same or similar function as the engine replaced is included in calculating the consecutive time period.

~~2.25~~ 2.29. "Ton" means 2,000 pounds.

~~2.26~~ 2.30. "Unit" means a stationary fossil fuel-fired boiler, combustion turbine, or combined cycle system.

~~2.27~~ 2.31. Other words and phrases used in this rule, unless otherwise indicated, will have the meaning ascribed to them in W.Va. Code §22-5-1 et seq. and 40 CFR §72.2.

§45-40-3. Measurements, abbreviations and acronyms.

3.1. Measurements, abbreviations and acronyms used in this rule are defined as follows:

3.1.a. Btu -- British thermal unit.

3.1.b. CEMS -- Continuous Emissions Monitoring System.

3.1.c. CO_2 -- carbon dioxide.

3.1.d. CSAPR -- Cross-State Air Pollution Rule.

~~NO_X -- nitrogen oxides.~~

3.1.e. g/bhp-hr -- grams per brake horsepower hour.

3.1.f. Hr -- hour.

3.1.g. MmBtu -- million Btu.

3.1.h. NO_X -- nitrogen oxides.

3.1.i. O_2 -- oxygen.

3.1.j. PEMS -- Predictive Emission Monitoring System.

3.1.k. SO_2 -- sulfur dioxide.

3.1.l. Tph -- tons per hour.

3.1.m. Yr -- year.

§45-40-4. Applicability.

4.1. The owner or operator of a unit that has a maximum design heat input greater than 250 mmBtu/hr, except for any unit subject to the federal Cross-State Air Pollution Rule (CSAPR) NO_X Ozone Season Group 2 Trading Program established under 40 CFR part 97, ~~Subpart BBBBB~~ subpart EEEEE, or an equivalent trading program established under ~~regulations~~ 45CSR43 and approved as a state implementation plan revision pursuant to 40 CFR ~~§52.38(b)(5)~~ §52.38(b)(9), shall comply with the ozone season NO_X emission limitation, and monitoring, recordkeeping and reporting requirements for ozone season emissions of NO_X-set forth in sections 5 and 6 below.

4.2. Effective May 1, 2009, the owner or operator of a large NO_X SIP Call engine shall comply with the ozone season NO_X reduction, compliance plan, monitoring, recordkeeping and reporting requirements set forth in section 9 below.

4.3. Effective May 1, 2009, the owner or operator of a kiln that meets the following applicability requirements shall comply with the ozone season NO_X control standards, ozone season NO_X compliance plan, reporting, monitoring and recordkeeping requirements set forth in section 10 below:

4.3.a. Long dry kilns ≥ 12 TPH process rate;

4.3.b. Long wet kilns ≥ 10 TPH process rate;

4.3.c. Preheater kilns ≥ 16 TPH process rate; and

4.3.d. Precalciner and preheater/precalciner kilns ≥ 22 TPH process rate.

§45-40-5. Ozone season NO_X emission limitation.

5.1. Ozone season NO_X limitation. -- Beginning May 1, 2016, the owner or operator of a unit that meets the applicability requirements set forth in subsection 4.1 shall limit emissions of NO_X during an ozone season pursuant to a NO_X emission rate for each unit contained in a permit issued under 45CSR13, 45CSR14, 45CSR19 or via consent order issued by the Secretary in accordance with W.Va. Code §22-5-4(a)(5). Such ozone season NO_X limitation may also include a limitation on operating time for a unit during the ozone season.

§45-40-6. Monitoring, recordkeeping and reporting requirements.

6.1. ~~The owner or operator of an applicable unit under subsection 4.1 shall operate certified continuous emission monitor systems necessary to attribute ozone season NO_X mass emissions to each unit, in accordance with 40 CFR part 75, subpart H. NO_X mass emissions measurements recorded and reported in accordance with 40 CFR Part 75, Subpart H shall be used to determine a unit's compliance with the ozone season NO_X emission limitation set forth in section 5.~~

The owner or operator of an applicable unit under subsection 4.1 shall comply with the provisions of 40 CFR part 75, subpart H (including use of any of the emissions monitoring methodologies which the unit qualifies to use under 40 CFR part 75) or shall install and operate a certified continuous emission monitoring system (CEMS) or a certified predictive emission monitoring system (PEMS) as necessary to attribute ozone season mass emissions of NO_X to each unit in accordance with subsection 6.2, 6.3, 6.4 or 6.5 below. Nitrogen oxides mass emissions measurements recorded and reported in accordance with subsection 6.2, 6.3, 6.4 or 6.5 shall be used to determine a unit's compliance with the ozone season NO_X emission limitation set forth in section 5.

6.2. An owner or operator that elects to demonstrate compliance in accordance with 40 CFR part 75, subpart H, shall meet the following requirements:

6.2.a. Install, calibrate, certify, maintain, monitor, and operate all required monitoring systems in accordance with 40 CFR part 75, subpart H;

6.2.b. Maintain records in accordance with 40 CFR part 75, subpart H ; and

6.2.c. Submit reports in accordance with 40 CFR part 75, subpart H.

6.3. An owner or operator that elects to demonstrate compliance using a CEMS in accordance with 40 CFR part 60, subpart Db and 45CSR16 shall meet the following requirements:

6.3.a. Install and certify the CEMS in accordance with Performance Specification 2 in Appendix B to 40 CFR part 60;

6.3.b. Operate and maintain the CEMS in accordance with 40 CFR §60.46b on a continuous basis;

6.3.c. Install, calibrate, maintain and operate the CEMS in accordance with the continuous monitoring requirements of:

6.3.c.1. 40 CFR §§60.48b and 60.13; or

6.3.c.2. 40 CFR §§60.47b(e) and 60.13;

6.3.d. For each month of the ozone season:

6.3.d.1. Determine total monthly heat input (in mmBtu) using fuel flowmeters and measurements or records of fuel gross calorific value, or in instances where fuel flow is not metered determine total monthly heat input (in mmBtu) from other measurements and records; and

6.3.d.2. Calculate total monthly NO_X mass emissions (in tons) by multiplying the total monthly heat input by the 30-day rolling average NO_X emission rate (in lb/mmBtu) determined under subdivisions 6.3.b and 6.3.c for the last day of the month on which the unit operated and divide by 2000;

6.3.e. Determine the total NO_X mass emissions for the ozone season (in tons) by summing the amounts of total monthly NO_X mass emissions calculated under subdivision 6.3.d for each month of the ozone season; and

6.3.f. Comply with the following reporting and recordkeeping requirements:

6.3.f.1. Maintain records in accordance with 40 CFR §60.49b and all additional records necessary to support the heat input data, 30-day rolling average NO_X emission rate data, and NO_X mass emissions computations described in subdivisions 6.3.d and 6.3.e; and

6.3.f.2. Submit to the Secretary reports in accordance with 40 CFR §60.49b and include the total monthly heat input data, 30-day rolling average NO_X emission rate data, and monthly and ozone season NO_X mass emissions computations described in subdivisions 6.3.d and 6.3.e.

6.4. An owner or operator not otherwise required to use a CEMS to demonstrate compliance with 40 CFR 60 may elect to demonstrate compliance using a PEMS and shall meet the following requirements:

6.4.a. Install and certify the PEMS in accordance with Performance Specification 16 in Appendix B to 40 CFR part 60 and the Quality Assurance Procedures for compliance PEMS in Appendix F to 40 CFR part 60;

6.4.b. Submit to the Secretary for approval a plan that identifies the operating conditions to be monitored and the records to be maintained in accordance with 40 CFR §60.49b(c). The request for plan approval shall be contained in the permit application or consent order required under subsection 6.6;

6.4.c. Operate and maintain the compliance PEMS on a continuous basis in accordance with 40 CFR §60.46b and the compliance PEMS requirements provided in Performance Specification 16 in Appendix B to 40 CFR part 60;

6.4.d. Comply with the continuous monitoring requirements of 40 CFR §§60.48b and 60.13;

6.4.e. For each month of the ozone season:

6.4.e.1. Determine total monthly heat input (in mmBtu) using fuel flowmeters and measurements or records of fuel gross calorific value, or in instances where fuel flow is not metered determine total monthly heat input (in mmBtu) from other measurements and records; and

6.4.e.2. Calculate total monthly NO_X mass emissions (in tons) by multiplying the total monthly heat input by the 30-day rolling average NO_X emission rate (in lb/mmBtu) determined under subdivisions 6.4.c and 6.4.d for the last day of the month on which the unit operated and divide by 2000;

6.4.f. Determine the total NO_X mass emissions for the ozone season (in tons) by summing the amounts of total monthly NO_X mass emissions calculated under subdivision 6.4.e for each month of the ozone season; and

6.4.g. Comply with the following reporting and recordkeeping requirements:

6.4.g.1. Maintain records in accordance with 40 CFR §60.49b and all additional records necessary to support the heat input data, 30-day rolling average NO_X emission rate data, and NO_X mass emissions computations described in subdivisions 6.4.e and 6.4.f; and

6.4.g.2. Submit to the Secretary reports in accordance with 40 CFR §60.49b and include the total monthly heat input data, 30-day rolling average NO_X emission rate data, and monthly and ozone season NO_X mass emissions computations described in subdivisions 6.4.e and 6.4.f.

6.5. An owner or operator of a combustion turbine unit that elects to demonstrate compliance using a CEMS shall meet the following requirements:

6.5.a. Install and certify the CEMS in accordance with Performance Specification 2 in Appendix B to 40 CFR part 60 and 45CSR16;

6.5.b. Conduct the performance tests in accordance with 40 CFR §60.4400;

6.5.c. Operate and maintain the CEMS in accordance with 40 CFR §60.4345 on a continuous basis;

6.5.d. Collect all CEMS data in accordance with 40 CFR §60.4350;

6.5.e. For each month of the ozone season:

6.5.e.1. Determine total monthly heat input (in mmBtu) using fuel flowmeters and measurements or records of fuel gross calorific value, or in instances where fuel flow is not metered determine total monthly heat input (in mmBtu) from other measurements and records; and

6.5.e.2. Calculate total monthly NO_X mass emissions (in tons) by multiplying the total monthly heat input by the 30-day rolling average NO_X emission rate (in lb/mmBtu) determined under subdivisions 6.5.c and 6.5.d for the last day of the month on which the unit operated and divide by 2000;

6.5.f. Determine the total NO_X mass emissions for the ozone season (in tons) by summing the amounts of total monthly NO_X mass emissions calculated under subdivision 6.5.e for each month of the ozone season; and

6.5.g. Comply with the following reporting and recordkeeping requirements:

6.5.g.1. Maintain records in accordance with 40 CFR §60.49b and all additional records necessary to support the heat input data, 30-day rolling average NO_X emission rate data, and NO_X mass emissions computations described in subdivisions 6.5.e and 6.5.f; and

6.4.g.2. Submit to the Secretary reports in accordance with 40 CFR §60.49b and include the total monthly heat input data, 30-day rolling average NO_X emission rate data, and monthly and ozone season NO_X mass emissions computations described in subdivisions 6.5.e and 6.5.f.

6.6. An owner or operator that elects an alternative monitoring scenario that is not currently contained in a permit issued pursuant to 45CSR13, 45CSR14 or 45CSR19 or via a consent order shall:

6.6.a. Submit a request for the alternative monitoring scenario in a permit application in accordance with 45CSR13, 45CSR14 or 45CSR19. For compliance options provided in 6.3, 6.4 or 6.5, the permit application should identify how NO_X emissions (in tons) will be determined using the CEMS or PEMS data; and.

6.6.b. Obtain approval from the Secretary via a permit issued under 45CSR13, 45CSR14 or

45CSR19 or via a consent order, effective prior to the start of the ozone season.

6.7. An owner or operator electing to demonstrate compliance with 40 CFR part 75, subpart H shall not use any alternative monitoring system, alternative reference method, or any other alternative for the requirements under 40 CFR part 75, subpart H prior to obtaining written approval by the Administrator in accordance with 40 CFR §75.70(h).

6.8. An owner or operator required to demonstrate compliance with a NO_X emissions limit under 40 CFR part 60, subpart Db shall not use an alternative monitoring system, reference method, or other CEMS requirements alternative under 40 CFR part 60, subpart Db prior to obtaining written approval by the Administrator.

6.9. The owner or operator of an applicable unit under subsection 4.1 may demonstrate compliance with the NO_X ozone season emission limitation set forth in section 5 in accordance with an alternative monitoring system under 40 CFR part 60, subpart Db without obtaining approval of the Secretary, provided the owner or operator obtained written approval from the Administrator prior to the effective date of this rule.

§45-40-7. Violation.

7.1. The owner or operator of an applicable unit under subsection 4.1 shall be subject to enforcement pursuant to W.Va. Code §22-5-1 et seq. or the CAA for excess emissions of NO_X during an ozone season if the unit emitted nitrogen oxides in excess of its ozone season NO_X emission limitation set forth in section 5.

§45-40-8. Ozone season NO_X budget demonstration.

8.1. Ozone season NO_X budget. -- The ozone season NO_X budget for all units that meet the applicability requirements set forth in subsection 4.1 is 2,184 tons.

8.2. Ozone season NO_X budget demonstration. -- Through the imposition of ozone season NO_X limitations under section 5, and assumption of maximum operating capacity or use of a limitation on operating time for a unit during the ozone season, the Secretary shall demonstrate to the Administrator that the ozone season NO_X emissions from all applicable units under subsection 4.1 meets the ozone season NO_X budget for these units set forth in subsection 8.1.

8.3. New units. -- The Secretary shall revise the ozone season NO_X budget demonstration under subsection 8.2 to accommodate the ozone season NO_X emissions of any new unit that meets the applicability requirements set forth in subsection 4.1. The ozone season NO_X emissions from any such new unit shall not cause the ozone season NO_X budget set forth in subsection 8.1 to be exceeded.

§45-40-9. Ozone season NO_X reduction requirements for stationary internal combustion engines.

9.1. Ozone season NO_X reduction. -- Effective May 1, 2009, the following owners or operators must reduce ozone season NO_X emissions by an amount equal to or greater than the applicable ozone season NO_X reduction listed in the table below. The applicable ozone season NO_X reduction is binding on the listed owners or operators, their successors and assigns:

Company	**Ozone Season NO_X Reduction**
Dominion	668 tons
Columbia Gas Transmission	235 tons
Total	**903 tons**

9.2. Compliance plan. -- Effective May 1, 2009, an owner or operator of a large stationary internal combustion engine under subsection 4.2 must not operate such engine in the period May 1 through September 30 of 2009 and any subsequent year unless the owner or operator demonstrates the applicable ozone season NO_X reduction under subsection 9.1 through the requirements of an approved compliance plan. The compliance plan ~~must~~ shall meet the following provisions:

9.2.a. Reserved;

9.2.b. Reserved;

9.2.c. The compliance plan must demonstrate quantifiable and enforceable NO_X emission reductions equal to or greater than the applicable ozone season NO_X reduction set forth in subsection 9.1, taking into account any creditable reduction in NO_X emissions under subdivisions 9.2.e, 9.2.f, 9.2.g, 9.2.h or 9.2.i;

9.2.d. The compliance plan may include and affect some or all stationary internal combustion engines or other significant NO_X emitting equipment at an individual facility, at several facilities, or at all facilities in West Virginia that are controlled by the same owner or operator;

9.2.e. The compliance plan may include credit for reductions in NO_X emissions due to the installation and operation of NO_X control equipment on large stationary internal combustion engines under subsection 9.1. The owner or operator will demonstrate to the satisfaction of the Secretary any creditable reductions in NO_X emissions from the installation and operation of such NO_X control equipment. The credit for reductions in NO_X emissions must be quantified based on the difference between uncontrolled and controlled NO_X emission rates, and ozone season operating hours;

9.2.f. The compliance plan may include credit for reductions in NO_X emissions due to the installation and operation of NO_X control equipment on uncontrolled stationary internal combustion engines not under subsection 4.2. The owner or operator will demonstrate to the satisfaction of the Secretary any creditable reductions in NO_X emissions from the installation and operation of such NO_X control equipment. Creditable reductions must be limited to reductions achieved after 1995 and from controls that were not part of the NO_X SIP Call engine inventory. The credit for reductions in NO_X emissions must be quantified based on the difference between uncontrolled and controlled NO_X emission rates, and ozone season operating hours;

9.2.g. The compliance plan may include credit for reductions in NO_X emissions due to replacement of any stationary internal combustion engines or other significant NO_X emitting equipment. The owner or operator will demonstrate to the satisfaction of the Secretary that the historic ozone season load capacity of any stationary internal combustion engine or other significant NO_X emitting equipment no longer in operation has been or would be replaced by one or more new stationary internal combustion engines, electric motors or turbines during each ozone season. The credit for reductions in NO_X emissions must be quantified based on the replaced engine's or other significant NO_X emitting equipment's ozone season NO_X emission rate and ozone season operating hours, and the projected emission rate and ozone season operating hours of any new replacement stationary internal combustion engines, electric motors or turbines;

9.2.h. The compliance plan may include credit for reductions in NO_X emissions due to reductions from shifting historic load capacity from an uncontrolled engine to a controlled engine, electric motor or turbine. The owner or operator will demonstrate to the satisfaction of the Secretary that a quantifiable net reduction in NO_X emissions has occurred or will occur due to a direct shift of ozone season load capacity from an uncontrolled engine to a controlled engine, electric motor or turbine. The credit for reductions in NO_X emissions must be quantified based on the uncontrolled engine's historic ozone season load capacity, NO_X emission rate (in g/bhp-hr), ozone season operating hours (in hr/ozone season), and the shifted ozone season load capacity, NO_X emission rate (in g/bhp-hr) and ozone season operating hours (in hr/ozone season) of the controlled stationary internal combustion engine, electric motor or turbine;

9.2.i. The compliance plan may include credit for reductions in NO_X emissions due to the installation and operation of NO_X controls on significant NO_X emitting equipment other than stationary internal combustion engines. The owner or operator will demonstrate to the satisfaction of the Secretary any creditable reductions in NO_X emissions from such NO_X emitting equipment. Creditable reductions must be limited to reductions achieved after 1995 and from controls that were not part of the NO_X SIP Call inventory. The credit for reductions in NO_X emissions must be quantified based on the difference between NO_X emission rates prior to installation of controls and controlled NO_X emission rates, and ozone season operating hours;

9.2.j. The compliance plan must include the following:

9.2.j.1. A list of affected engines or affected NO_X emitting equipment subject to the plan, including the manufacturer, model number, facility location and facility identification number;

9.2.j.2. The projected ozone season hours of operation for each affected engine or affected NO_X emitting equipment and supporting documentation;

9.2.j.3. A description of the NO_X emission controls installed, or to be installed, on each affected engine or affected NO_X emitting equipment, date or proposed date of installation, and documentation to support the controlled NO_X emission rates;

9.2.j.4. The uncontrolled and controlled NO_X emission rates in lb/hr and tons per ozone season for each affected engine or affected NO_X emitting equipment, as applicable;

9.2.j.5. A numerical demonstration that the sum of creditable NO_X emission reductions (in tons) obtained from all affected engines or affected NO_X emitting equipment included under a compliance plan will be equivalent to or greater than the owner or operator's applicable ozone season NO_X reduction under subsection 9.1, taking into account any creditable reductions in NO_X emissions under subdivisions 9.2.e, 9.2.f, 9.2.g, 9.2.h or 9.2.i; and

9.2.j.6. Performance test protocol and provisions for periodic monitoring, reporting and recordkeeping for each affected engine or affected NO_X emitting equipment.

9.2.k. Any creditable reductions in NO_X emissions under subdivisions 9.2.e, 9.2.f, 9.2.g, 9.2.h or 9.2.i must be quantifiable and enforceable through limitations included in a federally enforceable permit or compliance order; and

9.2.l. Any owner or operator with an approved compliance plan under subsection 9.2 may amend the plan with the written approval of the Secretary. Any NO_X emission rate or limitation included in such an amendment must be reflected in a federally enforceable permit or compliance order. The Secretary will either approve by order or disapprove by certified mail the amended compliance plan within 90 days of submission, and notify the Administrator of the compliance plan amendment approval upon issuance of order.

9.3. Monitoring requirements. -- Any owner or operator of an affected engine or affected NO_X emitting equipment subject to a compliance plan under subsection 9.2 must comply with the following monitoring requirements for each affected engine or affected NO_X emitting equipment:

9.3.a. The owner or operator must complete an initial performance test consistent with the requirements of 40 CFR part 60, Appendix A and 45CSR16, following installation of NO_X emission controls required to achieve the NO_X emission rate limit specified in subdivision 9.2.k; and

9.3.b. For the ozone season beginning in 2009, and each ozone season thereafter, the owner or operator will perform periodic monitoring sufficient to yield reliable data which demonstrate compliance with the limitations specified in subdivision 9.2.k. Such periodic monitoring must include:

9.3.b.1. A continuous emission monitoring system that complies with 40 CFR part 75 or 40 CFR part 60 and 45CSR16 and the quality assurance procedures specified in 40 CFR part 60, Appendix F and 45CSR16; or

9.3.b.2. Performance tests consistent with the requirements of 40 CFR part 60, Appendix A and 45CSR16, or portable monitors using ASTM D6522-00; and

9.3.b.2.A. A parametric monitoring program that specifies operating parameters, and their ranges, that will provide reasonable assurance that each affected engine or affected NO_X emitting equipment's emissions are consistent with the requirements of a compliance plan under subsection 9.2. Any such parametric monitoring program must be approved by the Secretary; or

9.3.b.2.B. A predictive emissions measurement system that relies on automated data collection from instruments. Any such predictive emissions measurement system must be approved by the Secretary.

9.4. Recordkeeping requirements. -- Any owner or operator of an affected engine or affected NO_X emitting equipment subject to a compliance plan under subsection 9.2 must comply with the following recordkeeping requirements:

9.4.a. Maintain all records necessary to demonstrate compliance with the requirements of the compliance plan and subsection 9.4 for a period of five calendar years at the facility where an affected engine or affected NO_X emitting equipment is located. Such records will be made available to the Secretary or Administrator upon request; and

9.4.b. For each affected engine or affected NO_X emitting equipment subject to a compliance plan under subsection 9.2, the owner or operator will maintain records of:

9.4.b.1. Identification and location of each affected engine or affected NO_X emitting equipment;

9.4.b.2. Calendar date of record;

9.4.b.3. The number of hours the affected engine or affected NO_X emitting equipment is operated during each ozone season compared to projected operating hours;

9.4.b.4. Type and quantity of fuel combusted; and

9.4.b.5. The results of all compliance tests.

9.5. Reporting requirements. -- Any owner or operator of an affected engine or affected NO_X emitting equipment subject to a compliance plan under subsection 9.2 must:

9.5.a. Notify the Secretary of any performance test under paragraph 9.3.b.2 at least 15 days in advance of such test;

9.5.b. Submit results of all performance tests to the Secretary within 30 days of completion of such tests; and

9.5.c. Submit a report which documents the total ozone season NO_X emissions and certifies compliance with the compliance plan for each affected engine or affected NO_X emitting equipment to the Secretary by October 31 of each year, beginning in 2009. The report must demonstrate and certify compliance with the applicable ozone season NO_X reduction set forth in subsection 9.1.

§45-40-10. Ozone season NO_X reduction requirements for emissions of NO_X from cement manufacturing kilns.

10.1. Standard requirements. -- Effective May 1, 2009, an owner or operator of any Portland cement kiln subject to this section must not operate the kiln during May 1 through September 30 unless the kiln has installed and operates during May 1 to September 30 with low-NO_X burners, mid-kiln firing or alternative control techniques, subject to approval by the Administrator, that achieve at least the same emissions decreases as low-NO_X burners or mid-kiln firing.

10.2. NO_X compliance plan. -- Any owner or operator of a source subject to the standard requirements of subsection 10.1 may elect to use NO_X reductions from any non-affected kiln at a source with a Portland cement kiln under subsection 4.3. If the owner or operator so elects, he or she must submit for approval to the Administrator by May 1, 2009 a NO_X compliance plan which demonstrates the method(s) by which the operator will achieve NO_X reductions from non-affected kilns which achieve at least the same emissions decreases set forth in the standard requirements of subsection 10.1.

10.3. Reporting requirements. -- Any owner or operator subject to the standard requirements of subsection 10.1 must comply with the following reporting requirements:

10.3.a. By May 1, 2009, submit to the Secretary and Administrator the identification number and type of each kiln subject to this section, the name and address of the plant where the kiln is located and the name and telephone number of the person responsible for demonstrating compliance with this section; and

10.3.b. Submit a report documenting for that kiln the total NO_X emissions from May 1 through September 30 of each year to the Secretary and Administrator by October 31 of each year, beginning in 2009.

10.4. Monitoring requirements.

10.4.a. Any owner or operator of a kiln subject to this section must complete an initial performance test and subsequent annual testing consistent with the requirements of 40 CFR part 60, Appendix A, Method 7, 7A, 7C, 7D or 7E; and 45CSR16; and

10.4.b. The operator may use the results of continuous emission monitoring system (CEMS) to replace the annual testing requirements set forth in subdivision 10.4.a. Such equipment must be installed and operated consistent with 40 CFR part 75.

10.5. Recordkeeping requirements. -- Any owner or operator of a kiln subject to this section must produce and maintain records which include, but are not limited to:

10.5.a. The emissions, in pounds of NO_X per ton of clinker produced from each affected Portland cement kiln;

10.5.b. The type of control used for each affected Portland cement kiln;

10.5.c. The date, time and duration of any startup, shutdown or malfunction in the operation of any of the cement kilns or the emissions monitoring equipment;

10.5.d. The results of any performance testing;

10.5.e. Daily cement kiln production records; and

10.5.f. All records required to be produced or maintained will be retained on site for a minimum of 5 years and be made available to the Secretary or Administrator upon request.

§45-40-11. Inconsistency between rules.

11.1. In the event of any inconsistency between this rule and any other rule of the ~~West Virginia Department of Environmental Protection~~ Division of Air Quality, the inconsistency will be resolved by the determination of the Secretary and the determination will be based upon the application of the more stringent provision, term, condition, method or rule.

ELECTRONIC CODE OF FEDERAL REGULATIONS

e-CFR data is current as of May 30, 2019

Title 40: Protection of Environment
PART 97—FEDERAL NOX BUDGET TRADING PROGRAM, CAIR NOX AND SO2 TRADING PROGRAMS, CSAPR NOX AND SO2 TRADING PROGRAMS, AND TEXAS SO2 TRADING PROGRAM

Subpart EEEEE—CSAPR NO_X Ozone Season Group 2 Trading Program

Contents

SOURCE: 81 FR 74621, Oct. 26, 2016, unless otherwise noted.

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§97.801 Purpose.

This subpart sets forth the general, designated representative, allowance, and monitoring provisions for the Cross-State Air Pollution Rule (CSAPR) NO_X Ozone Season Group 2 Trading Program, under section 110 of the Clean Air Act and §52.38 of this chapter, as a means of mitigating interstate transport of ozone and nitrogen oxides.

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§97.802 Definitions.

The terms used in this subpart shall have the meanings set forth in this section as follows, provided that any term that includes the acronym “CSAPR” shall be considered synonymous with a term that is used in a SIP revision approved by the Administrator under §52.38 or §52.39 of this chapter and that is substantively identical except for the inclusion of the acronym “TR” in place of the acronym “CSAPR”:

Acid Rain Program means a multi-state SO_2 and NO_X air pollution control and emission reduction program established by the Administrator under title IV of the Clean Air Act and parts 72 through 78 of this chapter.

Administrator means the Administrator of the United States Environmental Protection Agency or the Director of the Clean Air Markets Division (or its successor determined by the Administrator) of the United States Environmental Protection Agency, the Administrator's duly authorized representative under this subpart.

Allocate or *allocation* means, with regard to CSAPR NO_X Ozone Season Group 2 allowances, the determination by the Administrator, State, or permitting authority, in accordance with this subpart, §97.526(c), and any SIP revision submitted by the State and approved by the Administrator under §52.38(b)(6), (7), (8), or (9) of this chapter, of the amount of such CSAPR NO_X Ozone Season Group 2 allowances to be initially credited, at no cost to the recipient, to:

(1) A CSAPR NO_X Ozone Season Group 2 unit;

(2) A new unit set-aside;

(3) An Indian country new unit set-aside; or

(4) An entity not listed in paragraphs (1) through (3) of this definition;

(5) Provided that, if the Administrator, State, or permitting authority initially credits, to a CSAPR NO_X Ozone Season Group 2 unit qualifying for an initial credit, a credit in the amount of zero CSAPR NO_X Ozone Season Group 2 allowances, the CSAPR NO_X Ozone Season Group 2 unit will be treated as being allocated an amount (*i.e.,* zero) of CSAPR NO_X Ozone Season Group 2 allowances.

Allowable NO_X emission rate means, for a unit, the most stringent State or federal NO_X emission rate limit (in lb/MWh or, if in lb/mmBtu, converted to lb/MWh by multiplying it by the unit's heat rate in mmBtu/MWh) that is applicable to the unit and covers the longest averaging period not exceeding one year.

Allowance Management System means the system by which the Administrator records allocations, auctions, transfers, and deductions of CSAPR NO_X Ozone Season Group 2 allowances under the CSAPR NO_X Ozone Season Group 2 Trading Program. Such allowances are allocated, auctioned, recorded, held, transferred, or deducted only as whole allowances.

Allowance Management System account means an account in the Allowance Management System established by the Administrator for purposes of recording the allocation, auction, holding, transfer, or deduction of CSAPR NO_X Ozone Season Group 2 allowances.

Allowance transfer deadline means, for a control period in a given year, midnight of March 1 (if it is a business day), or midnight of the first business day thereafter (if March 1 is not a business day), immediately after such control period and is the deadline by which a CSAPR NO_X Ozone Season Group 2 allowance transfer must be submitted for recordation in a CSAPR NO_X Ozone Season Group 2 source's compliance account in order to be available for use in complying with the source's CSAPR NO_X Ozone Season Group 2 emissions limitation for such control period in accordance with §§97.806 and 97.824.

Alternate designated representative means, for a CSAPR NO_X Ozone Season Group 2 source and each CSAPR NO_X Ozone Season Group 2 unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with this subpart, to act on behalf of the designated representative in matters pertaining to the CSAPR NO_X Ozone Season Group 2 Trading Program. If the CSAPR NO_X Ozone Season Group 2 source is also subject to the Acid Rain Program, CSAPR NO_X Annual Trading Program, CSAPR SO_2 Group 1 Trading Program, or CSAPR SO_2 Group 2 Trading Program, then this natural person shall be the same natural person as the alternate designated representative as defined in the respective program.

Assurance account means an Allowance Management System account, established by the Administrator under §97.825(b)(3) for certain owners and operators of a group of one or more base CSAPR NO_X Ozone Season Group 2 sources and units in a given State (and Indian country within the borders of such State), in which are held CSAPR NO_X Ozone Season Group 2 allowances available for use for a control period in a given year in complying with the CSAPR NO_X Ozone Season Group 2 assurance provisions in accordance with §§97.806 and 97.825.

Auction means, with regard to CSAPR NO_X Ozone Season Group 2 allowances, the sale to any person by a State or permitting authority, in accordance with a SIP revision submitted by the State and approved by the Administrator under §52.38(b)(6), (8), or (9) of this chapter, of such CSAPR NO_X Ozone Season Group 2 allowances to be initially recorded in an Allowance Management System account.

Authorized account representative means, for a general account, the natural person who is authorized, in accordance with this subpart, to transfer and otherwise dispose of CSAPR NO_X Ozone Season Group 2 allowances held in the general account and, for a CSAPR NO_X Ozone Season Group 2 source's compliance account, the designated representative of the source.

Automated data acquisition and handling system or *DAHS* means the component of the continuous emission monitoring system, or other emissions monitoring system approved for use under this subpart, designed to interpret and convert individual output signals from pollutant concentration monitors, flow monitors, diluent gas monitors, and other component parts of the monitoring system to produce a continuous record of the measured parameters in the measurement units required by this subpart.

Base CSAPR NO_X Ozone Season Group 2 source means a source that includes one or more base CSAPR NO_X Ozone Season Group 2 units.

Base CSAPR NO_X Ozone Season Group 2 unit means a CSAPR NO_X Ozone Season Group 2 unit, provided that any unit that would not be a CSAPR NO_X Ozone Season Group 2 unit under §97.804(a) and (b) is not a base CSAPR NO_X Ozone Season Group 2 unit notwithstanding the provisions of any SIP revision approved by the Administrator under §52.38(b)(6), (8), or (9) of this chapter.

Biomass means—

(1) Any organic material grown for the purpose of being converted to energy;

(2) Any organic byproduct of agriculture that can be converted into energy; or

(3) Any material that can be converted into energy and is nonmerchantable for other purposes, that is segregated from other material that is nonmerchantable for other purposes, and that is;

(i) A forest-related organic resource, including mill residues, precommercial thinnings, slash, brush, or byproduct from conversion of trees to merchantable material; or

(ii) A wood material, including pallets, crates, dunnage, manufacturing and construction materials (other than pressure-treated, chemically-treated, or painted wood products), and landscape or right-of-way tree trimmings.

Boiler means an enclosed fossil- or other-fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

Bottoming-cycle unit means a unit in which the energy input to the unit is first used to produce useful thermal energy, where at least some of the reject heat from the useful thermal energy application or process is then used for electricity production.

Business day means a day that does not fall on a weekend or a federal holiday.

Certifying official means a natural person who is:

(1) For a corporation, a president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function or any other person who performs similar policy- or decision-making functions for the corporation;

(2) For a partnership or sole proprietorship, a general partner or the proprietor respectively; or

(3) For a local government entity or State, federal, or other public agency, a principal executive officer or ranking elected official.

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

Coal means “coal” as defined in §72.2 of this chapter.

Coal-derived fuel means any fuel (whether in a solid, liquid, or gaseous state) produced by the mechanical, thermal, or chemical processing of coal.

Cogeneration system means an integrated group, at a source, of equipment (including a boiler, or combustion turbine, and a generator) designed to produce useful thermal energy for industrial, commercial, heating, or cooling purposes and electricity through the sequential use of energy.

Cogeneration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine that is a topping-cycle unit or a bottoming-cycle unit:

(1) Operating as part of a cogeneration system; and

(2) Producing on an annual average basis—

(i) For a topping-cycle unit,

(A) Useful thermal energy not less than 5 percent of total energy output; and

(B) Useful power that, when added to one-half of useful thermal energy produced, is not less than 42.5 percent of total energy input, if useful thermal energy produced is 15 percent or more of total energy output, or not less than 45 percent of total energy input, if useful thermal energy produced is less than 15 percent of total energy output.

(ii) For a bottoming-cycle unit, useful power not less than 45 percent of total energy input;

(3) Provided that the requirements in paragraph (2) of this definition shall not apply to a calendar year referenced in paragraph (2) of this definition during which the unit did not operate at all;

(4) Provided that the total energy input under paragraphs (2)(i)(B) and (2)(ii) of this definition shall equal the unit's total energy input from all fuel, except biomass if the unit is a boiler; and

(5) Provided that, if, throughout its operation during the 12-month period or a calendar year referenced in paragraph (2) of this definition, a unit is operated as part of a cogeneration system and the cogeneration system meets on a system-wide basis the requirement in paragraph (2)(i)(B) or (2)(ii) of this definition, the unit shall be deemed to meet such requirement during that 12-month period or calendar year.

Combustion turbine means an enclosed device comprising:

(1) If the device is simple cycle, a compressor, a combustor, and a turbine and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine; and

(2) If the device is combined cycle, the equipment described in paragraph (1) of this definition and any associated duct burner, heat recovery steam generator, and steam turbine.

Commence commercial operation means, with regard to a unit:

(1) To have begun to produce steam, gas, or other heated medium used to generate electricity for sale or use, including test generation, except as provided in §97.805.

(i) For a unit that is a CSAPR NO_X Ozone Season Group 2 unit under §97.804 on the later of January 1, 2005 or the date the unit commences commercial operation as defined in the introductory text of paragraph (1) of this definition and that subsequently undergoes a physical change or is moved to a new location or source, such date shall remain the date of commencement of commercial operation of the unit, which shall continue to be treated as the same unit.

(ii) For a unit that is a CSAPR NO_X Ozone Season Group 2 unit under §97.804 on the later of January 1, 2005 or the date the unit commences commercial operation as defined in the introductory text of paragraph (1) of this definition and that is subsequently replaced by a unit at the same or a different source, such date shall remain the replaced unit's date of commencement of commercial operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1) or (2) of this definition as appropriate.

(2) Notwithstanding paragraph (1) of this definition and except as provided in §97.805, for a unit that is not a CSAPR NO_X Ozone Season Group 2 unit under §97.804 on the later of January 1, 2005 or the date the unit commences commercial operation as defined in the introductory text of paragraph (1) of this definition, the unit's date for commencement of commercial operation shall be the date on which the unit becomes a CSAPR NO_X Ozone Season Group 2 unit under §97.804.

(i) For a unit with a date for commencement of commercial operation as defined in the introductory text of paragraph (2) of this definition and that subsequently undergoes a physical change or is moved to a different location or source, such date shall remain the date of commencement of commercial operation of the unit, which shall continue to be treated as the same unit.

(ii) For a unit with a date for commencement of commercial operation as defined in the introductory text of paragraph (2) of this definition and that is subsequently replaced by a unit at the same or a different source, such date shall remain the replaced unit's date of commencement of commercial operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1) or (2) of this definition as appropriate.

Common designated representative means, with regard to a control period in a given year, a designated representative where, as of April 1 immediately after the allowance transfer deadline for such control period, the same natural person is authorized under §§97.813(a) and 97.815(a) as the designated representative for a group of one or more base CSAPR NO_X Ozone Season Group 2 sources and units located in a State (and Indian country within the borders of such State).

Common designated representative's assurance level means, with regard to a specific common designated representative and a State (and Indian country within the borders of such State) and control period in a given year for which the State assurance level is exceeded as described in §97.806(c)(2)(iii), the common designated representative's share of the State NO_X Ozone Season Group 2 trading budget with the variability limit for the State for such control period.

Common designated representative's share means, with regard to a specific common designated representative for a control period in a given year:

(1) With regard to a total amount of NO_X emissions from all base CSAPR NO_X Ozone Season Group 2 units in a State (and Indian country within the borders of such State) during such control period, the total tonnage of NO_X emissions during such control period from a group of one or more base CSAPR NO_X Ozone Season Group 2 units located in such State (and such Indian country) and having the common designated representative for such control period;

(2) With regard to a State NO_X Ozone Season Group 2 trading budget with the variability limit for such control period, the amount (rounded to the nearest allowance) equal to the sum of the total amount of CSAPR NO_X Ozone Season Group 2 allowances allocated for such control period to a group of one or more base CSAPR NO_X Ozone Season Group 2 units located in the State (and Indian country within the borders of such State) and having the common designated representative for such control period and the total amount of CSAPR NO_X Ozone Season Group 2 allowances purchased by an owner or operator of such base CSAPR NO_X Ozone Season Group 2 units in an auction for such control period and submitted by the State or the permitting authority to the Administrator for recordation in the compliance accounts for such base CSAPR NO_X Ozone Season Group 2 units in accordance with the CSAPR NO_X Ozone Season Group 2 allowance auction provisions in a SIP revision approved by the Administrator under §52.38(b)(6), (8), or (9) of this chapter, multiplied by the sum of the State NO_X Ozone Season Group 2 trading budget under §97.810(a) and the State's variability limit under §97.810(b) for such control period and divided by the greater of such State NO_X Ozone Season Group 2 trading budget or the sum of all amounts of CSAPR NO_X Ozone Season Group 2 allowances for such control period treated for purposes of this definition as having been allocated to or purchased in the State's auction for all such base CSAPR NO_X Ozone Season Group 2 units, provided that—

(i) The allocations of CSAPR NO_X Ozone Season Group 2 allowances for any control period taken into account for purposes of this definition exclude any CSAPR NO_X Ozone Season Group 2 allowances allocated for such control period under §97.526(c)(1) or (3), or under §97.526(c)(4) or (5) pursuant to an exception under §97.526(c)(1) or (3);

(ii) In the case of the base CSAPR NO_X Ozone Season Group 2 units at a base CSAPR NO_X Ozone Season Group 2 source in a State with regard to which CSAPR NO_X Ozone Season Group 2 allowances have been allocated under §97.526(c)(2) for a given control period, the units at each such source will be treated, solely for purposes of this definition, as having been allocated under §97.526(c)(2), or under §97.526(c)(4) or (5) pursuant to an exception under §97.526(c)(2), an amount of CSAPR NO_X Ozone Season Group 2 allowances for such control period equal to the sum of the total amount of CSAPR NO_X Ozone Season Group 1 allowances allocated for such control period to such units and the total amount of CSAPR NO_X Ozone Season Group 1 allowances purchased by an owner or operator of such units in an auction for such control period and submitted by the State or the permitting authority to the Administrator for recordation in the compliance account for such source in accordance with the CSAPR NO_X Ozone Season Group 1 allowance auction provisions in a SIP revision approved by the Administrator under §52.38(b)(4) or (5) of this chapter, divided by the conversion factor determined under §97.526(c)(2)(ii) with regard to the State's SIP revision under §52.38(b)(6) of this chapter, and rounded up to the nearest whole allowance; and

(iii) In the case of a base CSAPR NO_X Ozone Season Group 2 unit that operates during, but has no amount of CSAPR NO_X Ozone Season Group 2 allowances allocated under §§97.811 and 97.812 for, such control period, the unit shall be treated, solely for purposes of this definition, as being allocated an amount (rounded to the nearest allowance) of CSAPR NO_X Ozone Season Group 2 allowances for such control period equal to the unit's allowable NO_X emission rate applicable to such control period, multiplied by a capacity factor of 0.92 (if the unit is a boiler combusting any amount of coal or coal-derived fuel during such control period), 0.32 (if the unit is a simple combustion turbine during such control period), 0.71 (if the unit is a combined cycle turbine during such control period), 0.73 (if the unit is an integrated coal gasification combined cycle unit during such control period), or 0.44 (for any other unit), multiplied by the unit's maximum hourly load as reported in accordance with this subpart and by 3,672 hours/control period, and divided by 2,000 lb/ton.

Common stack means a single flue through which emissions from 2 or more units are exhausted.

Compliance account means an Allowance Management System account, established by the Administrator for a CSAPR NO_X Ozone Season Group 2 source under this subpart, in which any CSAPR NO_X Ozone Season Group 2 allowance allocations to the CSAPR NO_X Ozone Season Group 2 units at the source are recorded and in which are held any CSAPR NO_X Ozone Season Group 2 allowances available for use for a control period in a given year in complying with the source's CSAPR NO_X Ozone Season Group 2 emissions limitation in accordance with §§97.806 and 97.824.

Continuous emission monitoring system or *CEMS* means the equipment required under this subpart to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes and using an automated data acquisition and handling system (DAHS), a permanent record of NO_X emissions, stack gas volumetric flow rate, stack gas moisture content, and O_2 or CO_2 concentration (as applicable), in a manner consistent with part 75 of this chapter and §§97.830 through 97.835. The following systems are the principal types of continuous emission monitoring systems:

(1) A flow monitoring system, consisting of a stack flow rate monitor and an automated data acquisition and handling system and providing a permanent, continuous record of stack gas volumetric flow rate, in standard cubic feet per hour (scfh);

(2) A NO_X concentration monitoring system, consisting of a NO_X pollutant concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of NO_X emissions, in parts per million (ppm);

(3) A NO_X emission rate (or NO_X-diluent) monitoring system, consisting of a NO_X pollutant concentration monitor, a diluent gas (CO_2 or O_2) monitor, and an automated data acquisition and handling system and providing a permanent, continuous record of NO_X concentration, in parts per million (ppm), diluent gas concentration, in percent CO_2 or O_2, and NO_X emission rate, in pounds per million British thermal units (lb/mmBtu);

(4) A moisture monitoring system, as defined in §75.11(b)(2) of this chapter and providing a permanent, continuous record of the stack gas moisture content, in percent H_2O;

(5) A CO_2 monitoring system, consisting of a CO_2 pollutant concentration monitor (or an O_2 monitor plus suitable mathematical equations from which the CO_2 concentration is derived) and an automated data acquisition and handling system and providing a permanent, continuous record of CO_2 emissions, in percent CO_2; and

(6) An O_2 monitoring system, consisting of an O_2 concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of O_2, in percent O_2.

Control period means the period starting May 1 of a calendar year, except as provided in §97.806(c)(3), and ending on September 30 of the same year, inclusive.

CSAPR NO_X Annual Trading Program means a multi-state NO_X air pollution control and emission reduction program established in accordance with subpart AAAAA of this part and §52.38(a) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under §52.38(a)(3) or (4) of this chapter or that is established in a SIP revision approved by the Administrator under §52.38(a)(5) of this chapter), as a means of mitigating interstate transport of fine particulates and NO_X.

CSAPR NO_X Ozone Season Group 1 allowance means a limited authorization issued and allocated or auctioned by the Administrator under subpart BBBBB of this part, or by a State or permitting authority under a SIP revision approved by the Administrator under §52.38(b)(3), (4), or (5) of this chapter, to emit one ton of NO_X during a control period of the specified calendar year for which the authorization is allocated or auctioned or of any calendar year thereafter under the CSAPR NO_X Ozone Season Group 1 Trading Program.

CSAPR NO_X Ozone Season Group 1 Trading Program means a multi-state NO_X air pollution control and emission reduction program established in accordance with subpart BBBBB of this part and §52.38(b)(1), (b)(2)(i) and (ii), (b)(3) through (5), and (b)(10) through (12) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under §52.38(b)(3) or (4) of this chapter or that is established in a SIP revision approved by the Administrator under §52.38(b)(5) of this chapter), as a means of mitigating interstate transport of ozone and NO_X.

CSAPR NO_X Ozone Season Group 2 allowance means a limited authorization issued and allocated or auctioned by the Administrator under this subpart or §97.526(c), or by a State or permitting authority under a SIP revision approved by the Administrator under §52.38(b)(6), (7), (8), or (9) of this chapter, to emit one ton of NO_X during a control period of the specified calendar year for which the authorization is allocated or auctioned or of any calendar year thereafter under the CSAPR NO_X Ozone Season Group 2 Trading Program.

CSAPR NO_X Ozone Season Group 2 allowance deduction or *deduct CSAPR NO_X Ozone Season Group 2 allowances* means the permanent withdrawal of CSAPR NO_X Ozone Season Group 2 allowances by the Administrator from a compliance account (*e.g.,* in order to account for compliance with the CSAPR NO_X Ozone Season Group 2 emissions limitation) or from an assurance account (*e.g.,* in order to account for compliance with the assurance provisions under §§97.806 and 97.825).

CSAPR NO_X Ozone Season Group 2 allowances held or *hold CSAPR NO_X Ozone Season Group 2 allowances* means the CSAPR NO_X Ozone Season Group 2 allowances treated as included in an Allowance Management System account as of a specified point in time because at that time they:

(1) Have been recorded by the Administrator in the account or transferred into the account by a correctly submitted, but not yet recorded, CSAPR NO_X Ozone Season Group 2 allowance transfer in accordance with this subpart; and

(2) Have not been transferred out of the account by a correctly submitted, but not yet recorded, CSAPR NO_X Ozone Season Group 2 allowance transfer in accordance with this subpart.

CSAPR NO_X Ozone Season Group 2 emissions limitation means, for a CSAPR NO_X Ozone Season Group 2 source, the tonnage of NO_X emissions authorized in a control period in a given year by the CSAPR NO_X Ozone Season Group 2 allowances available for deduction for the source under §97.824(a) for such control period.

CSAPR NO_X Ozone Season Group 2 source means a source that includes one or more CSAPR NO_X Ozone Season Group 2 units.

CSAPR NO_X Ozone Season Group 2 Trading Program means a multi-state NO_X air pollution control and emission reduction program established in accordance with this subpart and §52.38(b)(1), (b)(2)(i) and (iii), (b)(6) through (11), and (b)(13) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under §52.38(b)(7) or (8) of this chapter or that is established in a SIP revision approved by the Administrator under §52.38(b)(6) or (9) of this chapter), as a means of mitigating interstate transport of ozone and NO_X.

CSAPR NO_X Ozone Season Group 2 unit means a unit that is subject to the CSAPR NO_X Ozone Season Group 2 Trading Program.

CSAPR SO_2 Group 1 Trading Program means a multi-state SO_2 air pollution control and emission reduction program established in accordance with subpart CCCCC of this part and §52.39(a), (b), (d) through (f), and (j) through (l) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under §52.39(d) or (e) of this chapter or that is established in a SIP revision approved by the Administrator under §52.39(f) of this chapter), as a means of mitigating interstate transport of fine particulates and SO_2.

CSAPR SO_2 Group 2 Trading Program means a multi-state SO_2 air pollution control and emission reduction program established in accordance with subpart DDDDD of this part and §52.39(a), (c), (g) through (k), and (m) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under §52.39(g) or (h) of this chapter or that is established in a SIP revision approved by the Administrator under §52.39(i) of this chapter), as a means of mitigating interstate transport of fine particulates and SO_2.

Designated representative means, for a CSAPR NO_X Ozone Season Group 2 source and each CSAPR NO_X Ozone Season Group 2 unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with this subpart, to represent and legally bind each owner and operator in matters pertaining to the CSAPR NO_X Ozone Season Group 2 Trading Program. If the CSAPR NO_X Ozone Season Group 2 source is also subject to the Acid Rain Program, CSAPR NO_X Annual Trading Program, CSAPR SO_2 Group 1 Trading Program, or CSAPR SO_2 Group 2 Trading Program, then this natural person shall be the same natural person as the designated representative as defined in the respective program.

Emissions means air pollutants exhausted from a unit or source into the atmosphere, as measured, recorded, and reported to the Administrator by the designated representative, and as modified by the Administrator:

(1) In accordance with this subpart; and

(2) With regard to a period before the unit or source is required to measure, record, and report such air pollutants in accordance with this subpart, in accordance with part 75 of this chapter.

Excess emissions means any ton of emissions from the CSAPR NO_X Ozone Season Group 2 units at a CSAPR NO_X Ozone Season Group 2 source during a control period in a given year that exceeds the CSAPR NO_X Ozone Season Group 2 emissions limitation for the source for such control period.

Fossil fuel means—

(1) Natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material; or

(2) For purposes of applying the limitation on “average annual fuel consumption of fossil fuel” in §97.804(b)(2)(i)(B) and (b)(2)(ii), natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

Fossil-fuel-fired means, with regard to a unit, combusting any amount of fossil fuel in 2005 or any calendar year thereafter.

General account means an Allowance Management System account, established under this subpart, that is not a compliance account or an assurance account.

Generator means a device that produces electricity.

Heat input means, for a unit for a specified period of unit operating time, the product (in mmBtu) of the gross calorific value of the fuel (in mmBtu/lb) fed into the unit multiplied by the fuel feed rate (in lb of fuel/time) and unit operating time, as measured, recorded, and reported to the Administrator by the designated representative and as modified by the Administrator in accordance with this subpart and excluding the heat derived from preheated combustion air, recirculated flue gases, or exhaust.

Heat input rate means, for a unit, the quotient (in mmBtu/hr) of the amount of heat input for a specified period of unit operating time (in mmBtu) divided by unit operating time (in hr) or, for a unit and a specific fuel, the amount of heat input attributed to the fuel (in mmBtu) divided by the unit operating time (in hr) during which the unit combusts the fuel.

Heat rate means, for a unit, the quotient (in mmBtu/unit of load) of the unit's maximum design heat input rate (in Btu/hr) divided by the product of 1,000,000 Btu/mmBtu and the unit's maximum hourly load.

Indian country means “Indian country” as defined in 18 U.S.C. 1151.

Life-of-the-unit, firm power contractual arrangement means a unit participation power sales agreement under which a utility or industrial customer reserves, or is entitled to receive, a specified amount or percentage of nameplate capacity and associated energy generated by any specified unit and pays its proportional amount of such unit's total costs, pursuant to a contract:

(1) For the life of the unit;

(2) For a cumulative term of no less than 30 years, including contracts that permit an election for early termination; or

(3) For a period no less than 25 years or 70 percent of the economic useful life of the unit determined as of the time the unit is built, with option rights to purchase or release some portion of the nameplate capacity and associated energy generated by the unit at the end of the period.

Maximum design heat input rate means, for a unit, the maximum amount of fuel per hour (in Btu/hr) that the unit is capable of combusting on a steady state basis as of the initial installation of the unit as specified by the manufacturer of the unit.

Monitoring system means any monitoring system that meets the requirements of this subpart, including a continuous emission monitoring system, an alternative monitoring system, or an excepted monitoring system under part 75 of this chapter.

Nameplate capacity means, starting from the initial installation of a generator, the maximum electrical generating output (in MWe, rounded to the nearest tenth) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings) as of such installation as specified by the manufacturer of the generator or, starting from the completion of any subsequent physical change in the generator resulting in an increase in the maximum electrical generating output that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount (in MWe, rounded to the nearest tenth) as of such completion as specified by the person conducting the physical change.

Natural gas means “natural gas” as defined in §72.2 of this chapter.

Newly affected CSAPR NO_X Ozone Season Group 2 unit means a unit that was not a CSAPR NO_X Ozone Season Group 2 unit when it began operating but that thereafter becomes a CSAPR NO_X Ozone Season Group 2 unit.

Operate or *operation* means, with regard to a unit, to combust fuel.

Operator means, for a CSAPR NO_X Ozone Season Group 2 source or a CSAPR NO_X Ozone Season Group 2 unit at a source respectively, any person who operates, controls, or supervises a CSAPR NO_X Ozone Season Group 2 unit at the source or the CSAPR NO_X Ozone Season Group 2 unit and shall include, but not be limited to, any holding company, utility system, or plant manager of such source or unit.

Owner means, for a CSAPR NO_X Ozone Season Group 2 source or a CSAPR NO_X Ozone Season Group 2 unit at a source respectively, any of the following persons:

(1) Any holder of any portion of the legal or equitable title in a CSAPR NO_X Ozone Season Group 2 unit at the source or the CSAPR NO_X Ozone Season Group 2 unit;

(2) Any holder of a leasehold interest in a CSAPR NO_X Ozone Season Group 2 unit at the source or the CSAPR NO_X Ozone Season Group 2 unit, provided that, unless expressly provided for in a leasehold agreement, "owner" shall not include a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based (either directly or indirectly) on the revenues or income from such CSAPR NO_X Ozone Season Group 2 unit; and

(3) Any purchaser of power from a CSAPR NO_X Ozone Season Group 2 unit at the source or the CSAPR NO_X Ozone Season Group 2 unit under a life-of-the-unit, firm power contractual arrangement.

Permanently retired means, with regard to a unit, a unit that is unavailable for service and that the unit's owners and operators do not expect to return to service in the future.

Permitting authority means "permitting authority" as defined in §§70.2 and 71.2 of this chapter.

Potential electrical output capacity means, for a unit (in MWh/yr), 33 percent of the unit's maximum design heat input rate (in Btu/hr), divided by 3,413 Btu/kWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 hr/yr.

Receive or *receipt of* means, when referring to the Administrator, to come into possession of a document, information, or correspondence (whether sent in hard copy or by authorized electronic transmission), as indicated in an official log, or by a notation made on the document, information, or correspondence, by the Administrator in the regular course of business.

Recordation, record, or *recorded* means, with regard to CSAPR NO_X Ozone Season Group 2 allowances, the moving of CSAPR NO_X Ozone Season Group 2 allowances by the Administrator into, out of, or between Allowance Management System accounts, for purposes of allocation, auction, transfer, or deduction.

Reference method means any direct test method of sampling and analyzing for an air pollutant as specified in §75.22 of this chapter.

Replacement, replace, or *replaced* means, with regard to a unit, the demolishing of a unit, or the permanent retirement and permanent disabling of a unit, and the construction of another unit (the replacement unit) to be used instead of the demolished or retired unit (the replaced unit).

Sequential use of energy means:

(1) The use of reject heat from electricity production in a useful thermal energy application or process; or

(2) The use of reject heat from a useful thermal energy application or process in electricity production.

Serial number means, for a CSAPR NO_X Ozone Season Group 2 allowance, the unique identification number assigned to each CSAPR NO_X Ozone Season Group 2 allowance by the Administrator.

Solid waste incineration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine that is a "solid waste incineration unit" as defined in section 129(g)(1) of the Clean Air Act.

Source means all buildings, structures, or installations located in one or more contiguous or adjacent properties under common control of the same person or persons. This definition does not change or otherwise affect the definition of "major source", "stationary source", or "source" as set forth and implemented in a title V operating permit program or any other program under the Clean Air Act.

State means one of the States that is subject to the CSAPR NO_X Ozone Season Group 2 Trading Program pursuant to §52.38(b)(1), (2)(i) and (iii), (6) through (11), and (13) of this chapter.

Submit or *serve* means to send or transmit a document, information, or correspondence to the person specified in accordance with the applicable regulation:

(1) In person;

(2) By United States Postal Service; or

(3) By other means of dispatch or transmission and delivery;

(4) Provided that compliance with any “submission” or “service” deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt.

Topping-cycle unit means a unit in which the energy input to the unit is first used to produce useful power, including electricity, where at least some of the reject heat from the electricity production is then used to provide useful thermal energy.

Total energy input means, for a unit, total energy of all forms supplied to the unit, excluding energy produced by the unit. Each form of energy supplied shall be measured by the lower heating value of that form of energy calculated as follows:

$$LHV = HHV - 10.55 (W + 9H)$$

where:

LHV = lower heating value of the form of energy in Btu/lb,

HHV = higher heating value of the form of energy in Btu/lb,

W = weight % of moisture in the form of energy, and

H = weight % of hydrogen in the form of energy.

Total energy output means, for a unit, the sum of useful power and useful thermal energy produced by the unit.

Unit means a stationary, fossil-fuel-fired boiler, stationary, fossil-fuel-fired combustion turbine, or other stationary, fossil-fuel-fired combustion device. A unit that undergoes a physical change or is moved to a different location or source shall continue to be treated as the same unit. A unit (the replaced unit) that is replaced by another unit (the replacement unit) at the same or a different source shall continue to be treated as the same unit, and the replacement unit shall be treated as a separate unit.

Unit operating day means, with regard to a unit, a calendar day in which the unit combusts any fuel.

Unit operating hour or *hour of unit operation* means, with regard to a unit, an hour in which the unit combusts any fuel.

Useful power means, with regard to a unit, electricity or mechanical energy that the unit makes available for use, excluding any such energy used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Useful thermal energy means thermal energy that is:

(1) Made available to an industrial or commercial process (not a power production process), excluding any heat contained in condensate return or makeup water;

(2) Used in a heating application (*e.g.,* space heating or domestic hot water heating); or

(3) Used in a space cooling application (*i.e.,* in an absorption chiller).

Utility power distribution system means the portion of an electricity grid owned or operated by a utility and dedicated to delivering electricity to customers.

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§97.803 Measurements, abbreviations, and acronyms.

Measurements, abbreviations, and acronyms used in this subpart are defined as follows:

Btu—British thermal unit

CO_2—carbon dioxide

CSAPR—Cross-State Air Pollution Rule

H_2O—water

hr—hour

kWh—kilowatt-hour

lb—pound

mmBtu—million Btu

MWe—megawatt electrical

MWh—megawatt-hour

NO_X—nitrogen oxides

O_2—oxygen

ppm—parts per million

scfh—standard cubic feet per hour

SIP—State implementation plan

SO_2—sulfur dioxide

TR—Transport Rule

yr—year

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§97.804 Applicability.

(a) Except as provided in paragraph (b) of this section:

(1) The following units in a State (and Indian country within the borders of such State) shall be CSAPR NO_X Ozone Season Group 2 units, and any source that includes one or more such units shall be a CSAPR NO_X Ozone Season Group 2 source, subject to the requirements of this subpart: Any stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine serving at any time, on or after January 1, 2005, a generator with nameplate capacity of more than 25 MWe producing electricity for sale.

(2) If a stationary boiler or stationary combustion turbine that, under paragraph (a)(1) of this section, is not a CSAPR NO_X Ozone Season Group 2 unit begins to combust fossil fuel or to serve a generator with nameplate capacity of more than 25 MWe producing electricity for sale, the unit shall become a CSAPR NO_X Ozone Season Group 2 unit as provided in paragraph (a)(1) of this section on the first date on which it both combusts fossil fuel and serves such generator.

(b) Any unit in a State (and Indian country within the borders of such State) that otherwise is a CSAPR NO_X Ozone Season Group 2 unit under paragraph (a) of this section and that meets the requirements set forth in paragraph (b)(1)(i) or (b)(2)(i) of this section shall not be a CSAPR NO_X Ozone Season Group 2 unit:

(1)(i) Any unit:

(A) Qualifying as a cogeneration unit throughout the later of 2005 or the 12-month period starting on the date the unit first produces electricity and continuing to qualify as a cogeneration unit throughout each calendar year ending after the later of 2005 or such 12-month period; and

(B) Not supplying in 2005 or any calendar year thereafter more than one-third of the unit's potential electrical output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale.

(ii) If, after qualifying under paragraph (b)(1)(i) of this section as not being a CSAPR NO_X Ozone Season Group 2 unit, a unit subsequently no longer meets all the requirements of paragraph (b)(1)(i) of this section, the unit shall become a CSAPR NO_X Ozone Season Group 2 unit starting on the earlier of January 1 after the first calendar year during which the unit first no longer qualifies as a cogeneration unit or January 1 after the first calendar year during which the unit no longer meets the requirements of paragraph (b)(1)(i)(B) of this section. The unit shall thereafter continue to be a CSAPR NO_X Ozone Season Group 2 unit.

(2)(i) Any unit:

(A) Qualifying as a solid waste incineration unit throughout the later of 2005 or the 12-month period starting on the date the unit first produces electricity and continuing to qualify as a solid waste incineration unit throughout each calendar year ending after the later of 2005 or such 12-month period; and

(B) With an average annual fuel consumption of fossil fuel for the first 3 consecutive calendar years of operation starting no earlier than 2005 of less than 20 percent (on a Btu basis) and an average annual fuel consumption of fossil fuel for any 3 consecutive calendar years thereafter of less than 20 percent (on a Btu basis).

(ii) If, after qualifying under paragraph (b)(2)(i) of this section as not being a CSAPR NO_X Ozone Season Group 2 unit, a unit subsequently no longer meets all the requirements of paragraph (b)(2)(i) of this section, the unit shall become a CSAPR NO_X Ozone Season Group 2 unit starting on the earlier of January 1 after the first calendar year during which the unit first no longer qualifies as a solid waste incineration unit or January 1 after the first 3 consecutive calendar years after 2005 for which the unit has an average annual fuel consumption of fossil fuel of 20 percent or more. The unit shall thereafter continue to be a CSAPR NO_X Ozone Season Group 2 unit.

(c) A certifying official of an owner or operator of any unit or other equipment may submit a petition (including any supporting documents) to the Administrator at any time for a determination concerning the applicability, under paragraphs (a) and (b) of this section or a SIP revision approved under §52.38(b)(6), (8), or (9) of this chapter, of the CSAPR NO_X Ozone Season Group 2 Trading Program to the unit or other equipment.

(1) *Petition content.* The petition shall be in writing and include the identification of the unit or other equipment and the relevant facts about the unit or other equipment. The petition and any other documents provided to the Administrator in connection with the petition shall include the following certification statement, signed by the certifying official: “I am authorized to make this submission on behalf of the owners and operators of the unit or other equipment for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.”

(2) *Response.* The Administrator will issue a written response to the petition and may request supplemental information determined by the Administrator to be relevant to such petition. The Administrator's determination concerning the applicability, under paragraphs (a) and (b) of this section, of the CSAPR NO_X Ozone Season Group 2 Trading Program to the unit or other equipment shall be binding on any State or permitting authority unless the Administrator determines that the petition or other documents or information provided in connection with the petition contained significant, relevant errors or omissions.

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§97.805 Retired unit exemption.

(a)(1) Any CSAPR NO_X Ozone Season Group 2 unit that is permanently retired shall be exempt from §97.806(b) and (c)(1), §97.824, and §§97.830 through 97.835.

(2) The exemption under paragraph (a)(1) of this section shall become effective the day on which the CSAPR NO_X Ozone Season Group 2 unit is permanently retired. Within 30 days of the unit's permanent retirement, the designated representative shall submit a statement to the Administrator. The statement shall state, in a format prescribed by the Administrator, that the unit was permanently retired on a specified date and will comply with the requirements of paragraph (b) of this section.

(b) *Special provisions.* (1) A unit exempt under paragraph (a) of this section shall not emit any NO_X, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under paragraph (a) of this section shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under paragraph (a) of this section shall comply with the requirements of the CSAPR NO_X Ozone Season Group 2 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under paragraph (a) of this section shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under this subpart, as a unit that commences commercial operation on the first date on which the unit resumes operation.

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§97.806 Standard requirements.

(a) *Designated representative requirements.* The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with §§97.813 through 97.818.

(b) *Emissions monitoring, reporting, and recordkeeping requirements.* (1) The owners and operators, and the designated representative, of each CSAPR NO_X Ozone Season Group 2 source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of §§97.830 through 97.835.

(2) The emissions data determined in accordance with §§97.830 through 97.835 shall be used to calculate allocations of CSAPR NO_X Ozone Season Group 2 allowances under §§97.811(a)(2) and (b) and 97.812 and to determine compliance with the CSAPR NO_X Ozone Season Group 2 emissions limitation and assurance provisions under paragraph (c) of this section, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with §§97.830 through 97.835 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(c) *NO_X emissions requirements*—(1) *CSAPR NO_X Ozone Season Group 2 emissions limitation.* (i) As of the allowance transfer deadline for a control period in a given year, the owners and operators of each CSAPR NO_X Ozone Season Group 2 source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall hold, in the source's compliance account, CSAPR NO_X Ozone Season Group 2 allowances available for deduction for such control period under §97.824(a) in an amount not less than the tons of total NO_X emissions for such control period from all CSAPR NO_X Ozone Season Group 2 units at the source.

(ii) If total NO_X emissions during a control period in a given year from the CSAPR NO_X Ozone Season Group 2 units at a CSAPR NO_X Ozone Season Group 2 source are in excess of the CSAPR NO_X Ozone Season Group 2 emissions limitation set forth in paragraph (c)(1)(i) of this section, then:

(A) The owners and operators of the source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall hold the CSAPR NO_X Ozone Season Group 2 allowances required for deduction under §97.824(d); and

(B) The owners and operators of the source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act.

(2) *CSAPR NO_X Ozone Season Group 2 assurance provisions.* (i) If total NO_X emissions during a control period in a given year from all base CSAPR NO_X Ozone Season Group 2 units at base CSAPR NO_X Ozone Season Group 2 sources in a State (and Indian country within the borders of such State) exceed the State assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such NO_X emissions during such control period exceeds the common designated representative's assurance level for the State and such control period, shall hold (in the assurance account established for the owners and operators of such group) CSAPR NO_X Ozone Season Group 2 allowances available for deduction for such control period under §97.825(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with §97.825(b), of multiplying—

(A) The quotient of the amount by which the common designated representative's share of such NO_X emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the State (and Indian country within the borders of such State) for such control period, by which each common designated representative's share of such NO_X emissions exceeds the respective common designated representative's assurance level; and

(B) The amount by which total NO_X emissions from all base CSAPR NO_X Ozone Season Group 2 units at base CSAPR NO_X Ozone Season Group 2 sources in the State (and Indian country within the borders of such State) for such control period exceed the State assurance level.

(ii) The owners and operators shall hold the CSAPR NO_X Ozone Season Group 2 allowances required under paragraph (c)(2)(i) of this section, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after the year of such control period.

(iii) Total NO_X emissions from all base CSAPR NO_X Ozone Season Group 2 units at base CSAPR NO_X Ozone Season Group 2 sources in a State (and Indian country within the borders of such State) during a control period in a given year exceed the State assurance level if such total NO_X emissions exceed the sum, for such control period, of the State NO_X Ozone Season Group 2 trading budget under §97.810(a) and the State's variability limit under §97.810(b).

(iv) It shall not be a violation of this subpart or of the Clean Air Act if total NO_X emissions from all base CSAPR NO_X Ozone Season Group 2 units at base CSAPR NO_X Ozone Season Group 2 sources in a State (and Indian country within the borders of such State) during a control period exceed the State assurance level or if a common designated representative's share of total NO_X emissions from the base CSAPR NO_X Ozone Season Group 2 units at base CSAPR NO_X Ozone Season Group 2 sources in a State (and Indian country within the borders of such State) during a control period exceeds the common designated representative's assurance level.

(v) To the extent the owners and operators fail to hold CSAPR NO_X Ozone Season Group 2 allowances for a control period in a given year in accordance with paragraphs (c)(2)(i) through (iii) of this section,

(A) The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B) Each CSAPR NO_X Ozone Season Group 2 allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(i) through (iii) of this section and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act.

(3) *Compliance periods.* (i) A CSAPR NO_X Ozone Season Group 2 unit shall be subject to the requirements under paragraph (c)(1) of this section for the control period starting on the later of May 1, 2017 or the deadline for meeting the unit's monitor certification requirements under §97.830(b) and for each control period thereafter.

(ii) A base CSAPR NO_X Ozone Season Group 2 unit shall be subject to the requirements under paragraph (c)(2) of this section for the control period starting on the later of May 1, 2017 or the deadline for meeting the unit's monitor certification requirements under §97.830(b) and for each control period thereafter.

(4) *Vintage of CSAPR NO_X Ozone Season Group 2 allowances held for compliance.* (i) A CSAPR NO_X Ozone Season Group 2 allowance held for compliance with the requirements under paragraph (c)(1)(i) of this section for a control period in a given year must be a CSAPR NO_X Ozone Season Group 2 allowance that was allocated or auctioned for such control period or a control period in a prior year.

(ii) A CSAPR NO_X Ozone Season Group 2 allowance held for compliance with the requirements under paragraphs (c)(1)(ii)(A) and (c)(2)(i) through (iii) of this section for a control period in a given year must be a CSAPR NO_X Ozone Season Group 2 allowance that was allocated or auctioned for a control period in a prior year or the control period in the given year or in the immediately following year.

(5) *Allowance Management System requirements.* Each CSAPR NO_X Ozone Season Group 2 allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with this subpart.

(6) *Limited authorization.* A CSAPR NO_X Ozone Season Group 2 allowance is a limited authorization to emit one ton of NO_X during the control period in one year. Such authorization is limited in its use and duration as follows:

(i) Such authorization shall only be used in accordance with the CSAPR NO_X Ozone Season Group 2 Trading Program; and

(ii) Notwithstanding any other provision of this subpart, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) *Property right.* A CSAPR NO_X Ozone Season Group 2 allowance does not constitute a property right.

(d) *Title V permit requirements.* (1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of CSAPR NO_X Ozone Season Group 2 allowances in accordance with this subpart.

(2) A description of whether a unit is required to monitor and report NO_X emissions using a continuous emission monitoring system (under subpart H of part 75 of this chapter), an excepted monitoring system (under appendices D and E to part 75 of this chapter), a low mass emissions excepted monitoring methodology (under §75.19 of this chapter), or an alternative monitoring system (under subpart E of part 75 of this chapter) in accordance with §§97.830 through 97.835 may be added to, or

changed in, a title V permit using minor permit modification procedures in accordance with §§70.7(e)(2) and 71.7(e)(1) of this chapter, provided that the requirements applicable to the described monitoring and reporting (as added or changed, respectively) are already incorporated in such permit. This paragraph explicitly provides that the addition of, or change to, a unit's description as described in the prior sentence is eligible for minor permit modification procedures in accordance with §§70.7(e)(2)(i)(B) and 71.7(e)(1)(i)(B) of this chapter.

(e) *Additional recordkeeping and reporting requirements.* (1) Unless otherwise provided, the owners and operators of each CSAPR NO_X Ozone Season Group 2 source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(i) The certificate of representation under §97.816 for the designated representative for the source and each CSAPR NO_X Ozone Season Group 2 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under §97.816 changing the designated representative.

(ii) All emissions monitoring information, in accordance with this subpart.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the CSAPR NO_X Ozone Season Group 2 Trading Program.

(2) The designated representative of a CSAPR NO_X Ozone Season Group 2 source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall make all submissions required under the CSAPR NO_X Ozone Season Group 2 Trading Program, except as provided in §97.818. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in parts 70 and 71 of this chapter.

(f) *Liability.* (1) Any provision of the CSAPR NO_X Ozone Season Group 2 Trading Program that applies to a CSAPR NO_X Ozone Season Group 2 source or the designated representative of a CSAPR NO_X Ozone Season Group 2 source shall also apply to the owners and operators of such source and of the CSAPR NO_X Ozone Season Group 2 units at the source.

(2) Any provision of the CSAPR NO_X Ozone Season Group 2 Trading Program that applies to a CSAPR NO_X Ozone Season Group 2 unit or the designated representative of a CSAPR NO_X Ozone Season Group 2 unit shall also apply to the owners and operators of such unit.

(g) *Effect on other authorities.* No provision of the CSAPR NO_X Ozone Season Group 2 Trading Program or exemption under §97.805 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a CSAPR NO_X Ozone Season Group 2 source or CSAPR NO_X Ozone Season Group 2 unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

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§97.807 Computation of time.

(a) Unless otherwise stated, any time period scheduled, under the CSAPR NO_X Ozone Season Group 2 Trading Program, to begin on the occurrence of an act or event shall begin on the day the act or event occurs.

(b) Unless otherwise stated, any time period scheduled, under the CSAPR NO_X Ozone Season Group 2 Trading Program, to begin before the occurrence of an act or event shall be computed so that the period ends the day before the act or event occurs.

(c) Unless otherwise stated, if the final day of any time period, under the CSAPR NO_X Ozone Season Group 2 Trading Program, is not a business day, the time period shall be extended to the next business day.

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§97.808 Administrative appeal procedures.

The administrative appeal procedures for decisions of the Administrator under the CSAPR NO_X Ozone Season Group 2 Trading Program are set forth in part 78 of this chapter.

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§97.809 [Reserved]

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§97.810 State NO_X Ozone Season Group 2 trading budgets, new unit set-asides, Indian country new unit set-asides, and variability limits.

(a) The State NO_X Ozone Season Group 2 trading budgets, new unit set-asides, and Indian country new unit set-asides for allocations of CSAPR NO_X Ozone Season Group 2 allowances for the control periods in 2017 and thereafter are as follows:

(1) *Alabama.* (i) The NO_X Ozone Season Group 2 trading budget is 13,211 tons.

(ii) The new unit set-aside is 255 tons.

(iii) The Indian country new unit set-aside is 13 tons.

(2) *Arkansas.* (i) The NO_X Ozone Season Group 2 trading budget for 2017 is 12,048 tons and for 2018 and thereafter is 9,210 tons.

(ii) The new unit set-aside for 2017 is 240 tons and for 2018 and thereafter is 185 tons.

(iii) [Reserved]

(3) *Georgia.* (i) The NO_X Ozone Season Group 2 trading budget is 8,481 tons.

(ii) The new unit set-aside is 168 tons.

(iii) [Reserved]

(4) *Illinois.* (i) The NO_X Ozone Season Group 2 trading budget is 14,601 tons.

(ii) The new unit set-aside is 302 tons.

(iii) [Reserved]

(5) *Indiana.* (i) The NO_X Ozone Season Group 2 trading budget is 23,303 tons.

(ii) The new unit set-aside is 468 tons.

(iii) [Reserved]

(6) *Iowa.* (i) The NO_X Ozone Season Group 2 trading budget is 11,272 tons.

(ii) The new unit set-aside is 324 tons.

(iii) The Indian country new unit set-aside is 11 tons.

(7) *Kansas.* (i) The NO_X Ozone Season Group 2 trading budget is 8,027 tons.

(ii) The new unit set-aside is 148 tons.

(iii) The Indian country new unit set-aside is 8 tons.

(8) *Kentucky.* (i) The NO_X Ozone Season Group 2 trading budget is 21,115 tons.

(ii) The new unit set-aside is 426 tons.

(iii) [Reserved]

(9) *Louisiana.* (i) The NO_X Ozone Season Group 2 trading budget is 18,639 tons.

(ii) The new unit set-aside is 352 tons.

(iii) The Indian country new unit set-aside is 19 tons.

(10) *Maryland.* (i) The NO_X Ozone Season Group 2 trading budget is 3,828 tons.

(ii) The new unit set-aside is 152 tons.

(iii) [Reserved]

(11) *Michigan.* (i) The NO_X Ozone Season Group 2 trading budget is 17,023 tons.

(ii) The new unit set-aside is 665 tons.

(iii) The Indian country new unit set-aside is 17 tons.

(12) *Mississippi.* (i) The NO_X Ozone Season Group 2 trading budget is 6,315 tons.

(ii) The new unit set-aside is 120 tons.

(iii) The Indian country new unit set-aside is 6 tons.

(13) *Missouri.* (i) The NO_X Ozone Season Group 2 trading budget is 15,780 tons.

(ii) The new unit set-aside is 324 tons.

(iii) [Reserved]

(14) *New Jersey.* (i) The NO_X Ozone Season Group 2 trading budget is 2,062 tons.

(ii) The new unit set-aside is 192 tons.

(iii) [Reserved]

(15) *New York.* (i) The NO_X Ozone Season Group 2 trading budget is 5,135 tons.

(ii) The new unit set-aside is 252 tons.

(iii) The Indian country new unit set-aside is 5 tons.

(16) *Ohio.* (i) The NO_X Ozone Season Group 2 trading budget is 19,522 tons.

(ii) The new unit set-aside is 401 tons.

(iii) [Reserved]

(17) *Oklahoma.* (i) The NO_X Ozone Season Group 2 trading budget is 11,641 tons.

(ii) The new unit set-aside is 221 tons.

(iii) The Indian country new unit set-aside is 12 tons.

(18) *Pennsylvania.* (i) The NO_X Ozone Season Group 2 trading budget is 17,952 tons.

(ii) The new unit set-aside is 541 tons.

(iii) [Reserved]

(19) *Tennessee.* (i) The NO_X Ozone Season Group 2 trading budget is 7,736 tons.

(ii) The new unit set-aside is 156 tons.

(iii) [Reserved]

(20) *Texas.* (i) The NO_X Ozone Season Group 2 trading budget is 52,301 tons.

(ii) The new unit set-aside is 998 tons.

(iii) The Indian country new unit set-aside is 52 tons.

(21) *Virginia.* (i) The NO_X Ozone Season Group 2 trading budget is 9,223 tons.

(ii) The new unit set-aside is 562 tons.

(iii) [Reserved]

(22) *West Virginia.* (i) The NO_X Ozone Season Group 2 trading budget is 17,815 tons.

(ii) The new unit set-aside is 356 tons.

(iii) [Reserved]

(23) *Wisconsin.* (i) The NO_X Ozone Season Group 2 trading budget is 7,915 tons.

(ii) The new unit set-aside is 151 tons.

(iii) The Indian country new unit set-aside is 8 tons.

(b) The States' variability limits for the State NO_X Ozone Season Group 2 trading budgets for the control periods in 2017 and thereafter are as follows:

(1) The variability limit for Alabama is 2,774 tons.

(2) The variability limit for Arkansas for 2017 is 2,530 tons and for 2018 and thereafter is 1,934 tons.

(3) The variability limit for Georgia is 1,781 tons.

(4) The variability limit for Illinois is 3,066 tons.

(5) The variability limit for Indiana is 4,894 tons.

(6) The variability limit for Iowa is 2,367 tons.

(7) The variability limit for Kansas is 1,686 tons.

(8) The variability limit for Kentucky is 4,434 tons.

(9) The variability limit for Louisiana is 3,914 tons.

(10) The variability limit for Maryland is 804 tons.

(11) The variability limit for Michigan is 3,575 tons.

(12) The variability limit for Mississippi is 1,326 tons.

(13) The variability limit for Missouri is 3,314 tons.

(14) The variability limit for New Jersey is 433 tons.

(15) The variability limit for New York is 1,078 tons.

(16) The variability limit for Ohio is 4,100 tons.

(17) The variability limit for Oklahoma is 2,445 tons.

(18) The variability limit for Pennsylvania is 3,770 tons.

(19) The variability limit for Tennessee is 1,625 tons.

(20) The variability limit for Texas is 10,983 tons.

(21) The variability limit for Virginia is 1,937 tons.

(22) The variability limit for West Virginia is 3,741 tons.

(23) The variability limit for Wisconsin is 1,662 tons.

(c) Each State NO_X Ozone Season Group 2 trading budget in this section includes any tons in a new unit set-aside or Indian country new unit set-aside but does not include any tons in a variability limit.

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§97.811 Timing requirements for CSAPR NO_X Ozone Season Group 2 allowance allocations.

(a) *Existing units.* (1) CSAPR NO_X Ozone Season Group 2 allowances are allocated, for the control periods in 2017 and each year thereafter, as provided in a notice of data availability issued by the Administrator. Providing an allocation to a unit in such notice does not constitute a determination that the unit is a CSAPR NO_X Ozone Season Group 2 unit, and not providing an allocation to a unit in such notice does not constitute a determination that the unit is not a CSAPR NO_X Ozone Season Group 2 unit.

(2) Notwithstanding paragraph (a)(1) of this section, if a unit provided an allocation in the notice of data availability issued under paragraph (a)(1) of this section does not operate, starting after 2016, during the control period in two consecutive years, such unit will not be allocated the CSAPR NO_X Ozone Season Group 2 allowances provided in such notice for the unit for the control periods in the fifth year after the first such year and in each year after that fifth year. All CSAPR NO_X Ozone Season Group 2 allowances that would otherwise have been allocated to such unit will be allocated to the new unit set-aside for the State where such unit is located and for the respective years involved. If such unit resumes operation, the Administrator will allocate CSAPR NO_X Ozone Season Group 2 allowances to the unit in accordance with paragraph (b) of this section.

(b) *New units*—(1) *New unit set-asides.* (i) By June 1, 2017 and June 1 of each year thereafter, the Administrator will calculate the CSAPR NO_X Ozone Season Group 2 allowance allocation to each CSAPR NO_X Ozone Season Group 2 unit in a State, in accordance with §97.812(a)(2) through (7) and (12), for the control period in the year of the applicable calculation deadline under this paragraph and will promulgate a notice of data availability of the results of the calculations.

(ii) For each notice of data availability required in paragraph (b)(1)(i) of this section, the Administrator will provide an opportunity for submission of objections to the calculations referenced in such notice.

(A) Objections shall be submitted by the deadline specified in each notice of data availability required in paragraph (b)(1)(i) of this section and shall be limited to addressing whether the calculations (including the identification of the CSAPR NO_X Ozone Season Group 2 units) are in accordance with §97.812(a)(2) through (7) and (12) and §§97.806(b)(2) and 97.830 through 97.835.

(B) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(1)(ii)(A) of this section. By August 1 immediately after the promulgation of each notice of data availability required in paragraph (b)(1)(i) of this section, the Administrator will promulgate a notice of data availability of any adjustments that the Administrator determines to be necessary with regard to allocations under §97.812(a)(2) through (7) and (12) and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(1)(ii)(A) of this section.

(iii) If the new unit set-aside for such control period contains any CSAPR NO_X Ozone Season Group 2 allowances that have not been allocated in the applicable notice of data availability required in paragraph (b)(1)(ii) of this section, the Administrator will promulgate, by December 15 immediately after such notice, a notice of data availability that identifies any CSAPR NO_X Ozone Season Group 2 units that commenced commercial operation during the period starting January 1 of the year before the year of such control period and ending November 30 of the year of such control period.

(iv) For each notice of data availability required in paragraph (b)(1)(iii) of this section, the Administrator will provide an opportunity for submission of objections to the identification of CSAPR NO_X Ozone Season Group 2 units in such notice.

(A) Objections shall be submitted by the deadline specified in each notice of data availability required in paragraph (b)(1)(iii) of this section and shall be limited to addressing whether the identification of CSAPR NO_X Ozone Season Group 2 units in such notice is in accordance with paragraph (b)(1)(iii) of this section.

(B) The Administrator will adjust the identification of CSAPR NO_X Ozone Season Group 2 units in each notice of data availability required in paragraph (b)(1)(iii) of this section to the extent necessary to ensure that it is in accordance with paragraph (b)(1)(iii) of this section and will calculate the CSAPR NO_X Ozone Season Group 2 allowance allocation to each CSAPR NO_X Ozone Season Group 2 unit in accordance with §97.812(a)(9), (10), and (12) and §§97.806(b)(2) and 97.830 through 97.835. By February 15 immediately after the promulgation of each notice of data availability required in paragraph (b)(1)(iii) of this section, the Administrator will promulgate a notice of data availability of any adjustments of the identification of CSAPR NO_X Ozone Season Group 2 units that the Administrator determines to be necessary, the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(1)(iv)(A) of this section, and the results of such calculations.

(v) To the extent any CSAPR NO_X Ozone Season Group 2 allowances are added to the new unit set-aside after promulgation of each notice of data availability required in paragraph (b)(1)(iv) of this section, the Administrator will promulgate additional notices of data availability, as deemed appropriate, of the allocation of such CSAPR NO_X Ozone Season Group 2 allowances in accordance with §97.812(a)(10).

(2) *Indian country new unit set-asides.* (i) By June 1, 2017 and June 1 of each year thereafter, the Administrator will calculate the CSAPR NO_X Ozone Season Group 2 allowance allocation to each CSAPR NO_X Ozone Season Group 2 unit in Indian country within the borders of a State, in accordance with §97.812(b)(2) through (7) and (12), for the control period in the year of the applicable calculation deadline under this paragraph and will promulgate a notice of data availability of the results of the calculations.

(ii) For each notice of data availability required in paragraph (b)(2)(i) of this section, the Administrator will provide an opportunity for submission of objections to the calculations referenced in such notice.

(A) Objections shall be submitted by the deadline specified in each notice of data availability required in paragraph (b)(2)(i) of this section and shall be limited to addressing whether the calculations (including the identification of the CSAPR NO_X Ozone Season Group 2 units) are in accordance with §97.812(b)(2) through (7) and (12) and §§97.806(b)(2) and 97.830 through 97.835.

(B) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(2)(ii)(A) of this section. By August 1 immediately after the promulgation of each notice of data availability required in paragraph (b)(2)(i) of this section, the Administrator will promulgate a notice of data availability of any adjustments that the Administrator determines to be necessary with regard to allocations under §97.812(b)(2) through (7) and (12) and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(2)(ii)(A) of this section.

(iii) If the Indian country new unit set-aside for such control period contains any CSAPR NO_X Ozone Season Group 2 allowances that have not been allocated in the applicable notice of data availability required in paragraph (b)(2)(ii) of this section, the Administrator will promulgate, by December 15 immediately after such notice, a notice of data availability that identifies any CSAPR NO_X Ozone Season Group 2 units that commenced commercial operation during the period starting January 1 of the year before the year of such control period and ending November 30 of the year of such control period.

(iv) For each notice of data availability required in paragraph (b)(2)(iii) of this section, the Administrator will provide an opportunity for submission of objections to the identification of CSAPR NO_X Ozone Season Group 2 units in such notice.

(A) Objections shall be submitted by the deadline specified in each notice of data availability required in paragraph (b)(2)(iii) of this section and shall be limited to addressing whether the identification of CSAPR NO_X Ozone Season Group 2 units in such notice is in accordance with paragraph (b)(2)(iii) of this section.

(B) The Administrator will adjust the identification of CSAPR NO_X Ozone Season Group 2 units in each notice of data availability required in paragraph (b)(2)(iii) of this section to the extent necessary to ensure that it is in accordance with paragraph (b)(2)(iii) of this section and will calculate the CSAPR NO_X Ozone Season Group 2 allowance allocation to each CSAPR NO_X Ozone Season Group 2 unit in accordance with §97.812(b)(9), (10), and (12) and §§97.806(b)(2) and 97.830 through 97.835. By February 15 immediately after the promulgation of each notice of data availability required in paragraph (b)(2)(iii) of this section, the Administrator will promulgate a notice of data availability of any adjustments of the identification of CSAPR NO_X Ozone Season Group 2 units that the Administrator determines to be necessary, the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(2)(iv)(A) of this section, and the results of such calculations.

(v) To the extent any CSAPR NO_X Ozone Season Group 2 allowances are added to the Indian country new unit set-aside after promulgation of each notice of data availability required in paragraph (b)(2)(iv) of this section, the Administrator will promulgate additional notices of data availability, as deemed appropriate, of the allocation of such CSAPR NO_X Ozone Season Group 2 allowances in accordance with §97.812(b)(10).

(c) *Units incorrectly allocated CSAPR NO_X Ozone Season Group 2 allowances.* (1) For each control period in 2017 and thereafter, if the Administrator determines that CSAPR NO_X Ozone Season Group 2 allowances were allocated under paragraph (a) of this section, or under a provision of a SIP revision approved under §52.38(b)(6), (7), (8), or (9) of this chapter, where such control period and the recipient are covered by the provisions of paragraph (c)(1)(i) of this section or were allocated under §97.812(a)(2) through (7), (9), and (12) and (b)(2) through (7), (9), and (12), or under a provision of a SIP revision approved under §52.38(b)(6), (8), or (9) of this chapter, where such control period and the recipient are covered by the provisions of paragraph (c)(1)(ii) of this section, then the Administrator will notify the designated representative of the recipient and will act in accordance with the procedures set forth in paragraphs (c)(2) through (5) of this section:

(i)(A) The recipient is not actually a CSAPR NO_X Ozone Season Group 2 unit under §97.804 as of May 1, 2017 and is allocated CSAPR NO_X Ozone Season Group 2 allowances for such control period or, in the case of an allocation under a provision of a SIP revision approved under §52.38(b)(6), (7), (8), or (9) of this chapter, the recipient is not actually a CSAPR NO_X Ozone Season Group 2 unit as of May 1, 2017 and is allocated CSAPR NO_X Ozone Season Group 2 allowances for such control period that the SIP revision provides should be allocated only to recipients that are CSAPR NO_X Ozone Season Group 2 units as of May 1, 2017; or

(B) The recipient is not located as of May 1 of the control period in the State from whose NO_X Ozone Season Group 2 trading budget the CSAPR NO_X Ozone Season Group 2 allowances allocated under paragraph (a) of this section, or under a provision of a SIP revision approved under §52.38(b)(6), (7), (8), or (9) of this chapter, were allocated for such control period.

(ii) The recipient is not actually a CSAPR NO_X Ozone Season Group 2 unit under §97.804 as of May 1 of such control period and is allocated CSAPR NO_X Ozone Season Group 2 allowances for such control period or, in the case of an allocation under a provision of a SIP revision approved under §52.38(b)(6), (8), or (9) of this chapter, the recipient is not actually a CSAPR NO_X Ozone Season Group 2 unit as of May 1 of such control period and is allocated CSAPR NO_X Ozone Season Group 2 allowances for such control period that the SIP revision provides should be allocated only to recipients that are CSAPR NO_X Ozone Season Group 2 units as of May 1 of such control period.

(2) Except as provided in paragraph (c)(3) or (4) of this section, the Administrator will not record such CSAPR NO_X Ozone Season Group 2 allowances under §97.821.

(3) If the Administrator already recorded such CSAPR NO_X Ozone Season Group 2 allowances under §97.821 and if the Administrator makes the determination under paragraph (c)(1) of this section before making deductions for the source that includes such recipient under §97.824(b) for such control period, then the Administrator will deduct from the account in which such CSAPR NO_X Ozone Season Group 2 allowances were recorded an amount of CSAPR NO_X Ozone Season Group 2 allowances allocated for the same or a prior control period equal to the amount of such already recorded CSAPR NO_X Ozone Season Group 2 allowances. The authorized account representative shall ensure that there are sufficient CSAPR NO_X Ozone Season Group 2 allowances in such account for completion of the deduction.

(4) If the Administrator already recorded such CSAPR NO_X Ozone Season Group 2 allowances under §97.821 and if the Administrator makes the determination under paragraph (c)(1) of this section after making deductions for the source that includes such recipient under §97.824(b) for such control period, then the Administrator will not make any deduction to take account of such already recorded CSAPR NO_X Ozone Season Group 2 allowances.

(5)(i) With regard to the CSAPR NO_X Ozone Season Group 2 allowances that are not recorded, or that are deducted as an incorrect allocation, in accordance with paragraphs (c)(2) and (3) of this section for a recipient under paragraph (c)(1)(i) of this section, the Administrator will:

(A) Transfer such CSAPR NO_X Ozone Season Group 2 allowances to the new unit set-aside for such control period for the State from whose NO_X Ozone Season Group 2 trading budget the CSAPR NO_X Ozone Season Group 2 allowances were allocated; or

(B) If the State has a SIP revision approved under §52.38(b)(6), (8), or (9) of this chapter covering such control period, include such CSAPR NO_X Ozone Season Group 2 allowances in the portion of the State NO_X Ozone Season Group 2 trading budget that may be allocated for such control period in accordance with such SIP revision.

(ii) With regard to the CSAPR NO_X Ozone Season Group 2 allowances that were not allocated from the Indian country new unit set-aside for such control period and that are not recorded, or that are deducted as an incorrect allocation, in accordance with paragraphs (c)(2) and (3) of this section for a recipient under paragraph (c)(1)(ii) of this section, the Administrator will:

(A) Transfer such CSAPR NO_X Ozone Season Group 2 allowances to the new unit set-aside for such control period; or

(B) If the State has a SIP revision approved under §52.38(b)(6), (8), or (9) of this chapter covering such control period, include such CSAPR NO_X Ozone Season Group 2 allowances in the portion of the State NO_X Ozone Season Group 2 trading budget that may be allocated for such control period in accordance with such SIP revision.

(iii) With regard to the CSAPR NO_X Ozone Season Group 2 allowances that were allocated from the Indian country new unit set-aside for such control period and that are not recorded, or that are deducted as an incorrect allocation, in accordance with paragraphs (c)(2) and (3) of this section for a recipient under paragraph (c)(1)(ii) of this section, the Administrator will transfer such CSAPR NO_X Ozone Season Group 2 allowances to the Indian country new unit set-aside for such control period.

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§97.812 CSAPR NO_X Ozone Season Group 2 allowance allocations to new units.

(a) For each control period in 2017 and thereafter and for the CSAPR NO_X Ozone Season Group 2 units in each State, the Administrator will allocate CSAPR NO_X Ozone Season Group 2 allowances to the CSAPR NO_X Ozone Season Group 2 units as follows:

(1) The CSAPR NO_X Ozone Season Group 2 allowances will be allocated to the following CSAPR NO_X Ozone Season Group 2 units, except as provided in paragraph (a)(10) of this section:

(i) CSAPR NO_X Ozone Season Group 2 units that are not allocated an amount of CSAPR NO_X Ozone Season Group 2 allowances in the notice of data availability issued under §97.811(a)(1);

(ii) CSAPR NO_X Ozone Season Group 2 units whose allocation of an amount of CSAPR NO_X Ozone Season Group 2 allowances for such control period in the notice of data availability issued under §97.811(a)(1) is covered by §97.811(c)(2) or (3);

(iii) CSAPR NO_X Ozone Season Group 2 units that are allocated an amount of CSAPR NO_X Ozone Season Group 2 allowances for such control period in the notice of data availability issued under §97.811(a)(1), which allocation is terminated for such control period pursuant to §97.811(a)(2), and that operate during the control period immediately preceding such control period; or

(iv) For purposes of paragraph (a)(9) of this section, CSAPR NO_X Ozone Season Group 2 units under §97.811(c)(1)(ii) whose allocation of an amount of CSAPR NO_X Ozone Season Group 2 allowances for such control period in the notice of data availability issued under §97.811(b)(1)(ii)(B) is covered by §97.811(c)(2) or (3).

(2) The Administrator will establish a separate new unit set-aside for the State for each such control period. Each such new unit set-aside will be allocated CSAPR NO_X Ozone Season Group 2 allowances in an amount equal to the applicable amount of tons of NO_X emissions as set forth in §97.810(a) and will be allocated additional CSAPR NO_X Ozone Season Group 2 allowances (if any) in accordance with §97.811(a)(2) and (c)(5) and paragraph (b)(10) of this section.

(3) The Administrator will determine, for each CSAPR NO_X Ozone Season Group 2 unit described in paragraph (a)(1) of this section, an allocation of CSAPR NO_X Ozone Season Group 2 allowances for the later of the following control periods and for each subsequent control period:

(i) The control period in 2017;

(ii) The first control period after the control period in which the CSAPR NO_X Ozone Season Group 2 unit commences commercial operation;

(iii) For a unit described in paragraph (a)(1)(ii) of this section, the first control period in which the CSAPR NO_X Ozone Season Group 2 unit operates in the State after operating in another jurisdiction and for which the unit is not already allocated one or more CSAPR NO_X Ozone Season Group 2 allowances; and

(iv) For a unit described in paragraph (a)(1)(iii) of this section, the first control period after the control period in which the unit resumes operation.

(4)(i) The allocation to each CSAPR NO_X Ozone Season Group 2 unit described in paragraphs (a)(1)(i) through (iii) of this section and for each control period described in paragraph (a)(3) of this section will be an amount equal to the unit's total tons of NO_X emissions during the immediately preceding control period.

(ii) The Administrator will adjust the allocation amount in paragraph (a)(4)(i) of this section in accordance with paragraphs (a)(5) through (7) and (12) of this section.

(5) The Administrator will calculate the sum of the CSAPR NO_X Ozone Season Group 2 allowances determined for all such CSAPR NO_X Ozone Season Group 2 units under paragraph (a)(4)(i) of this section in the State for such control period.

(6) If the amount of CSAPR NO_X Ozone Season Group 2 allowances in the new unit set-aside for the State for such control period is greater than or equal to the sum under paragraph (a)(5) of this section, then the Administrator will allocate the amount of CSAPR NO_X Ozone Season Group 2 allowances determined for each such CSAPR NO_X Ozone Season Group 2 unit under paragraph (a)(4)(i) of this section.

(7) If the amount of CSAPR NO_X Ozone Season Group 2 allowances in the new unit set-aside for the State for such control period is less than the sum under paragraph (a)(5) of this section, then the Administrator will allocate to each such CSAPR NO_X Ozone Season Group 2 unit the amount of the CSAPR NO_X Ozone Season Group 2 allowances determined under paragraph (a)(4)(i) of this section for the unit, multiplied by the amount of CSAPR NO_X Ozone Season Group 2 allowances in the new unit

set-aside for such control period, divided by the sum under paragraph (a)(5) of this section, and rounded to the nearest allowance.

(8) The Administrator will notify the public, through the promulgation of the notices of data availability described in §97.811(b)(1)(i) and (ii), of the amount of CSAPR NO_X Ozone Season Group 2 allowances allocated under paragraphs (a)(2) through (7) and (12) of this section for such control period to each CSAPR NO_X Ozone Season Group 2 unit eligible for such allocation.

(9) If, after completion of the procedures under paragraphs (a)(5) through (8) of this section for such control period, any unallocated CSAPR NO_X Ozone Season Group 2 allowances remain in the new unit set-aside for the State for such control period, the Administrator will allocate such CSAPR NO_X Ozone Season Group 2 allowances as follows—

(i) The Administrator will determine, for each unit described in paragraph (a)(1) of this section that commenced commercial operation during the period starting January 1 of the year before the year of such control period and ending November 30 of the year of such control period, the positive difference (if any) between the unit's emissions during such control period and the amount of CSAPR NO_X Ozone Season Group 2 allowances referenced in the notice of data availability required under §97.811(b)(1)(ii) for the unit for such control period;

(ii) The Administrator will determine the sum of the positive differences determined under paragraph (a)(9)(i) of this section;

(iii) If the amount of unallocated CSAPR NO_X Ozone Season Group 2 allowances remaining in the new unit set-aside for the State for such control period is greater than or equal to the sum determined under paragraph (a)(9)(ii) of this section, then the Administrator will allocate the amount of CSAPR NO_X Ozone Season Group 2 allowances determined for each such CSAPR NO_X Ozone Season Group 2 unit under paragraph (a)(9)(i) of this section; and

(iv) If the amount of unallocated CSAPR NO_X Ozone Season Group 2 allowances remaining in the new unit set-aside for the State for such control period is less than the sum under paragraph (a)(9)(ii) of this section, then the Administrator will allocate to each such CSAPR NO_X Ozone Season Group 2 unit the amount of the CSAPR NO_X Ozone Season Group 2 allowances determined under paragraph (a)(9)(i) of this section for the unit, multiplied by the amount of unallocated CSAPR NO_X Ozone Season Group 2 allowances remaining in the new unit set-aside for such control period, divided by the sum under paragraph (a)(9)(ii) of this section, and rounded to the nearest allowance.

(10) If, after completion of the procedures under paragraphs (a)(9) and (12) of this section for such control period, any unallocated CSAPR NO_X Ozone Season Group 2 allowances remain in the new unit set-aside for the State for such control period, the Administrator will allocate to each CSAPR NO_X Ozone Season Group 2 unit that is in the State, is allocated an amount of CSAPR NO_X Ozone Season Group 2 allowances in the notice of data availability issued under §97.811(a)(1), and continues to be allocated CSAPR NO_X Ozone Season Group 2 allowances for such control period in accordance with §97.811(a)(2), an amount of CSAPR NO_X Ozone Season Group 2 allowances equal to the following: The total amount of such remaining unallocated CSAPR NO_X Ozone Season Group 2 allowances in such new unit set-aside, multiplied by the unit's allocation under §97.811(a) for such control period, divided by the remainder of the amount of tons in the applicable State NO_X Ozone Season Group 2 trading budget minus the sum of the amounts of tons in such new unit set-aside and the Indian country new unit set-aside for the State for such control period, and rounded to the nearest allowance.

(11) The Administrator will notify the public, through the promulgation of the notices of data availability described in §97.811(b)(1)(iii), (iv), and (v), of the amount of CSAPR NO_X Ozone Season Group 2 allowances allocated under paragraphs (a)(9), (10), and (12) of this section for such control period to each CSAPR NO_X Ozone Season Group 2 unit eligible for such allocation.

(12)(i) Notwithstanding the requirements of paragraphs (a)(2) through (11) of this section, if the calculations of allocations of a new unit set-aside for a control period in a given year under paragraph (a)(7) of this section, paragraphs (a)(6) and (a)(9)(iv) of this section, or paragraphs (a)(6), (a)(9)(iii), and (a)(10) of this section would otherwise result in total allocations of such new unit set-aside exceeding the total amount of such new unit set-aside, then the Administrator will adjust the results of the calculations under paragraph (a)(7), (a)(9)(iv), or (a)(10) of this section, as applicable, as follows. The Administrator will list the CSAPR NO_X Ozone Season Group 2 units in descending order based on the amount of such units' allocations under paragraph (a)(7), (a)(9)(iv), or (a)(10) of this section, as applicable, and, in cases of equal allocation amounts, in alphabetical order of the relevant source's name and numerical order of the relevant unit's identification number, and will reduce each unit's allocation under paragraph (a)(7), (a)(9)(iv), or (a)(10) of this section, as applicable, by one CSAPR NO_X Ozone Season Group 2 allowance (but not below zero) in the order in which the units are listed and will repeat this reduction process as necessary, until the total allocations of such new unit set-aside equal the total amount of such new unit set-aside.

(ii) Notwithstanding the requirements of paragraphs (a)(10) and (11) of this section, if the calculations of allocations of a new unit set-aside for a control period in a given year under paragraphs (a)(6), (a)(9)(iii), and (a)(10) of this section would otherwise result in a total allocations of such new unit set-aside less than the total amount of such new unit set-aside, then the Administrator will adjust the results of the calculations under paragraph (a)(10) of this section, as follows. The Administrator will list the CSAPR NO_X Ozone Season Group 2 units in descending order based on the amount of such units' allocations under paragraph (a)(10) of this section and, in cases of equal allocation amounts, in alphabetical order of the relevant source's name and numerical order of the relevant unit's identification number, and will increase each unit's allocation under paragraph (a)(10) of this section by one CSAPR NO_X Ozone Season Group 2 allowance in the order in which the units are listed and will repeat this increase process as necessary, until the total allocations of such new unit set-aside equal the total amount of such new unit set-aside.

(b) For each control period in 2017 and thereafter and for the CSAPR NO_X Ozone Season Group 2 units located in Indian country within the borders of each State, the Administrator will allocate CSAPR NO_X Ozone Season Group 2 allowances to the CSAPR NO_X Ozone Season Group 2 units as follows:

(1) The CSAPR NO_X Ozone Season Group 2 allowances will be allocated to the following CSAPR NO_X Ozone Season Group 2 units, except as provided in paragraph (b)(10) of this section:

(i) CSAPR NO_X Ozone Season Group 2 units that are not allocated an amount of CSAPR NO_X Ozone Season Group 2 allowances in the notice of data availability issued under §97.811(a)(1); or

(ii) For purposes of paragraph (b)(9) of this section, CSAPR NO_X Ozone Season Group 2 units under §97.811(c)(1)(ii) whose allocation of an amount of CSAPR NO_X Ozone Season Group 2 allowances for such control period in the notice of data availability issued under §97.811(b)(2)(ii)(B) is covered by §97.811(c)(2) or (3).

(2) The Administrator will establish a separate Indian country new unit set-aside for the State for each such control period. Each such Indian country new unit set-aside will be allocated CSAPR NO_X Ozone Season Group 2 allowances in an amount equal to the applicable amount of tons of NO_X emissions as set forth in §97.810(a) and will be allocated additional CSAPR NO_X Ozone Season Group 2 allowances (if any) in accordance with §97.811(c)(5).

(3) The Administrator will determine, for each CSAPR NO_X Ozone Season Group 2 unit described in paragraph (b)(1) of this section, an allocation of CSAPR NO_X Ozone Season Group 2 allowances for the later of the following control periods and for each subsequent control period:

(i) The control period in 2017; and

(ii) The first control period after the control period in which the CSAPR NO_X Ozone Season Group 2 unit commences commercial operation.

(4)(i) The allocation to each CSAPR NO_X Ozone Season Group 2 unit described in paragraph (b)(1)(i) of this section and for each control period described in paragraph (b)(3) of this section will be an amount equal to the unit's total tons of NO_X emissions during the immediately preceding control period.

(ii) The Administrator will adjust the allocation amount in paragraph (b)(4)(i) of this section in accordance with paragraphs (b)(5) through (7) and (12) of this section.

(5) The Administrator will calculate the sum of the CSAPR NO_X Ozone Season Group 2 allowances determined for all such CSAPR NO_X Ozone Season Group 2 units under paragraph (b)(4)(i) of this section in Indian country within the borders of the State for such control period.

(6) If the amount of CSAPR NO_X Ozone Season Group 2 allowances in the Indian country new unit set-aside for the State for such control period is greater than or equal to the sum under paragraph (b)(5) of this section, then the Administrator will allocate the amount of CSAPR NO_X Ozone Season Group 2 allowances determined for each such CSAPR NO_X Ozone Season Group 2 unit under paragraph (b)(4)(i) of this section.

(7) If the amount of CSAPR NO_X Ozone Season Group 2 allowances in the Indian country new unit set-aside for the State for such control period is less than the sum under paragraph (b)(5) of this section, then the Administrator will allocate to each such CSAPR NO_X Ozone Season Group 2 unit the amount of the CSAPR NO_X Ozone Season Group 2 allowances determined under paragraph (b)(4)(i) of this section for the unit, multiplied by the amount of CSAPR NO_X Ozone Season Group 2 allowances in the Indian country new unit set-aside for such control period, divided by the sum under paragraph (b)(5) of this section, and rounded to the nearest allowance.

(8) The Administrator will notify the public, through the promulgation of the notices of data availability described in §97.811(b)(2)(i) and (ii), of the amount of CSAPR NO_X Ozone Season Group 2 allowances allocated under paragraphs (b)(2)

through (7) and (12) of this section for such control period to each CSAPR NO_X Ozone Season Group 2 unit eligible for such allocation.

(9) If, after completion of the procedures under paragraphs (b)(5) through (8) of this section for such control period, any unallocated CSAPR NO_X Ozone Season Group 2 allowances remain in the Indian country new unit set-aside for the State for such control period, the Administrator will allocate such CSAPR NO_X Ozone Season Group 2 allowances as follows—

(i) The Administrator will determine, for each unit described in paragraph (b)(1) of this section that commenced commercial operation during the period starting January 1 of the year before the year of such control period and ending November 30 of the year of such control period, the positive difference (if any) between the unit's emissions during such control period and the amount of CSAPR NO_X Ozone Season Group 2 allowances referenced in the notice of data availability required under §97.811(b)(2)(ii) for the unit for such control period;

(ii) The Administrator will determine the sum of the positive differences determined under paragraph (b)(9)(i) of this section;

(iii) If the amount of unallocated CSAPR NO_X Ozone Season Group 2 allowances remaining in the Indian country new unit set-aside for the State for such control period is greater than or equal to the sum determined under paragraph (b)(9)(ii) of this section, then the Administrator will allocate the amount of CSAPR NO_X Ozone Season Group 2 allowances determined for each such CSAPR NO_X Ozone Season Group 2 unit under paragraph (b)(9)(i) of this section; and

(iv) If the amount of unallocated CSAPR NO_X Ozone Season Group 2 allowances remaining in the Indian country new unit set-aside for the State for such control period is less than the sum under paragraph (b)(9)(ii) of this section, then the Administrator will allocate to each such CSAPR NO_X Ozone Season Group 2 unit the amount of the CSAPR NO_X Ozone Season Group 2 allowances determined under paragraph (b)(9)(i) of this section for the unit, multiplied by the amount of unallocated CSAPR NO_X Ozone Season Group 2 allowances remaining in the Indian country new unit set-aside for such control period, divided by the sum under paragraph (b)(9)(ii) of this section, and rounded to the nearest allowance.

(10) If, after completion of the procedures under paragraphs (b)(9) and (12) of this section for such control period, any unallocated CSAPR NO_X Ozone Season Group 2 allowances remain in the Indian country new unit set-aside for the State for such control period, the Administrator will:

(i) Transfer such unallocated CSAPR NO_X Ozone Season Group 2 allowances to the new unit set-aside for the State for such control period; or

(ii) If the State has a SIP revision approved under §52.38(b)(6), (8), or (9) of this chapter covering such control period, include such unallocated CSAPR NO_X Ozone Season Group 2 allowances in the portion of the State NO_X Ozone Season Group 2 trading budget that may be allocated for such control period in accordance with such SIP revision.

(11) The Administrator will notify the public, through the promulgation of the notices of data availability described in §97.811(b)(2)(iii), (iv), and (v), of the amount of CSAPR NO_X Ozone Season Group 2 allowances allocated under paragraphs (b)(9), (10), and (12) of this section for such control period to each CSAPR NO_X Ozone Season Group 2 unit eligible for such allocation.

(12)(i) Notwithstanding the requirements of paragraphs (b)(2) through (11) of this section, if the calculations of allocations of an Indian country new unit set-aside for a control period in a given year under paragraph (b)(7) of this section, paragraphs (b)(6) and (b)(9)(iv) of this section, or paragraphs (b)(6), (b)(9)(iii), and (b)(10) of this section would otherwise result in total allocations of such Indian country new unit set-aside exceeding the total amount of such Indian country new unit set-aside, then the Administrator will adjust the results of the calculations under paragraph (b)(7), (b)(9)(iv), or (b)(10) of this section, as applicable, as follows. The Administrator will list the CSAPR NO_X Ozone Season Group 2 units in descending order based on the amount of such units' allocations under paragraph (b)(7), (b)(9)(iv), or (b)(10) of this section, as applicable, and, in cases of equal allocation amounts, in alphabetical order of the relevant source's name and numerical order of the relevant unit's identification number, and will reduce each unit's allocation under paragraph (b)(7), (b)(9)(iv), or (b)(10) of this section, as applicable, by one CSAPR NO_X Ozone Season Group 2 allowance (but not below zero) in the order in which the units are listed and will repeat this reduction process as necessary, until the total allocations of such Indian country new unit set-aside equal the total amount of such Indian country new unit set-aside.

(ii) Notwithstanding the requirements of paragraphs (b)(10) and (11) of this section, if the calculations of allocations of an Indian country new unit set-aside for a control period in a given year under paragraphs (b)(6), (b)(9)(iii), and (b)(10) of this section would otherwise result in a total allocations of such Indian country new unit set-aside less than the total amount of such Indian country new unit set-aside, then the Administrator will adjust the results of the calculations under paragraph (b)(10) of this section, as follows. The Administrator will list the CSAPR NO_X Ozone Season Group 2 units in descending order based on the amount of such units' allocations under paragraph (b)(10) of this section and, in cases of equal allocation amounts, in alphabetical order of the relevant source's name and numerical order of the relevant unit's identification number, and will increase each unit's allocation under paragraph (b)(10) of this section by one CSAPR NO_X Ozone Season Group 2 allowance in the order in which the units are listed and will repeat this increase process as necessary, until the total allocations of such Indian country new unit set-aside equal the total amount of such Indian country new unit set-aside.

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§97.813 Authorization of designated representative and alternate designated representative.

(a) Except as provided under §97.815, each CSAPR NO_X Ozone Season Group 2 source, including all CSAPR NO_X Ozone Season Group 2 units at the source, shall have one and only one designated representative, with regard to all matters under the CSAPR NO_X Ozone Season Group 2 Trading Program.

(1) The designated representative shall be selected by an agreement binding on the owners and operators of the source and all CSAPR NO_X Ozone Season Group 2 units at the source and shall act in accordance with the certification statement in §97.816(a)(4)(iii).

(2) Upon and after receipt by the Administrator of a complete certificate of representation under §97.816:

(i) The designated representative shall be authorized and shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner and operator of the source and each CSAPR NO_X Ozone Season Group 2 unit at the source in all matters pertaining to the CSAPR NO_X Ozone Season Group 2 Trading Program, notwithstanding any agreement between the designated representative and such owners and operators; and

(ii) The owners and operators of the source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall be bound by any decision or order issued to the designated representative by the Administrator regarding the source or any such unit.

(b) Except as provided under §97.815, each CSAPR NO_X Ozone Season Group 2 source may have one and only one alternate designated representative, who may act on behalf of the designated representative. The agreement by which the alternate designated representative is selected shall include a procedure for authorizing the alternate designated representative to act in lieu of the designated representative.

(1) The alternate designated representative shall be selected by an agreement binding on the owners and operators of the source and all CSAPR NO_X Ozone Season Group 2 units at the source and shall act in accordance with the certification statement in §97.816(a)(4)(iii).

(2) Upon and after receipt by the Administrator of a complete certificate of representation under §97.816,

(i) The alternate designated representative shall be authorized;

(ii) Any representation, action, inaction, or submission by the alternate designated representative shall be deemed to be a representation, action, inaction, or submission by the designated representative; and

(iii) The owners and operators of the source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall be bound by any decision or order issued to the alternate designated representative by the Administrator regarding the source or any such unit.

(c) Except in this section, §97.802, and §§97.814 through 97.818, whenever the term “designated representative” (as distinguished from the term “common designated representative”) is used in this subpart, the term shall be construed to include the designated representative or any alternate designated representative.

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§97.814 Responsibilities of designated representative and alternate designated representative.

(a) Except as provided under §97.818 concerning delegation of authority to make submissions, each submission under the CSAPR NO_X Ozone Season Group 2 Trading Program shall be made, signed, and certified by the designated representative or alternate designated representative for each CSAPR NO_X Ozone Season Group 2 source and CSAPR NO_X Ozone Season Group 2 unit for which the submission is made. Each such submission shall include the following certification statement by the designated representative or alternate designated representative: “I am authorized to make this submission on behalf of the owners and operators of the source or units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(b) The Administrator will accept or act on a submission made for a CSAPR NO_X Ozone Season Group 2 source or a CSAPR NO_X Ozone Season Group 2 unit only if the submission has been made, signed, and certified in accordance with paragraph (a) of this section and §97.818.

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§97.815 Changing designated representative and alternate designated representative; changes in owners and operators; changes in units at the source.

(a) *Changing designated representative.* The designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under §97.816. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new designated representative and the owners and operators of the CSAPR NO_X Ozone Season Group 2 source and the CSAPR NO_X Ozone Season Group 2 units at the source.

(b) *Changing alternate designated representative.* The alternate designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under §97.816. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new alternate designated representative, the designated representative, and the owners and operators of the CSAPR NO_X Ozone Season Group 2 source and the CSAPR NO_X Ozone Season Group 2 units at the source.

(c) *Changes in owners and operators.* (1) In the event an owner or operator of a CSAPR NO_X Ozone Season Group 2 source or a CSAPR NO_X Ozone Season Group 2 unit at the source is not included in the list of owners and operators in the certificate of representation under §97.816, such owner or operator shall be deemed to be subject to and bound by the certificate of representation, the representations, actions, inactions, and submissions of the designated representative and any alternate designated representative of the source or unit, and the decisions and orders of the Administrator, as if the owner or operator were included in such list.

(2) Within 30 days after any change in the owners and operators of a CSAPR NO_X Ozone Season Group 2 source or a CSAPR NO_X Ozone Season Group 2 unit at the source, including the addition or removal of an owner or operator, the designated representative or any alternate designated representative shall submit a revision to the certificate of representation under §97.816 amending the list of owners and operators to reflect the change.

(d) *Changes in units at the source.* Within 30 days of any change in which units are located at a CSAPR NO_X Ozone Season Group 2 source (including the addition or removal of a unit), the designated representative or any alternate designated representative shall submit a certificate of representation under §97.816 amending the list of units to reflect the change.

(1) If the change is the addition of a unit that operated (other than for purposes of testing by the manufacturer before initial installation) before being located at the source, then the certificate of representation shall identify, in a format prescribed by the Administrator, the entity from whom the unit was purchased or otherwise obtained (including name, address, telephone number, and facsimile number (if any)), the date on which the unit was purchased or otherwise obtained, and the date on which the unit became located at the source.

(2) If the change is the removal of a unit, then the certificate of representation shall identify, in a format prescribed by the Administrator, the entity to which the unit was sold or that otherwise obtained the unit (including name, address, telephone number, and facsimile number (if any)), the date on which the unit was sold or otherwise obtained, and the date on which the unit became no longer located at the source.

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§97.816 Certificate of representation.

(a) A complete certificate of representation for a designated representative or an alternate designated representative shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the CSAPR NO_X Ozone Season Group 2 source, and each CSAPR NO_X Ozone Season Group 2 unit at the source, for which the certificate of representation is submitted, including source name, source category and NAICS code (or, in the absence of a NAICS code, an equivalent code), State, plant code, county, latitude and longitude, unit identification

number and type, identification number and nameplate capacity (in MWe, rounded to the nearest tenth) of each generator served by each such unit, actual or projected date of commencement of commercial operation, and a statement of whether such source is located in Indian country. If a projected date of commencement of commercial operation is provided, the actual date of commencement of commercial operation shall be provided when such information becomes available.

(2) The name, address, email address (if any), telephone number, and facsimile transmission number (if any) of the designated representative and any alternate designated representative.

(3) A list of the owners and operators of the CSAPR NO_X Ozone Season Group 2 source and of each CSAPR NO_X Ozone Season Group 2 unit at the source.

(4) The following certification statements by the designated representative and any alternate designated representative—

(i) "I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owners and operators of the source and each CSAPR NO_X Ozone Season Group 2 unit at the source."

(ii) "I certify that I have all the necessary authority to carry out my duties and responsibilities under the CSAPR NO_X Ozone Season Group 2 Trading Program on behalf of the owners and operators of the source and of each CSAPR NO_X Ozone Season Group 2 unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the Administrator regarding the source or unit."

(iii) "Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a CSAPR NO_X Ozone Season Group 2 unit, or where a utility or industrial customer purchases power from a CSAPR NO_X Ozone Season Group 2 unit under a life-of-the-unit, firm power contractual arrangement, I certify that: I have given a written notice of my selection as the `designated representative' or `alternate designated representative', as applicable, and of the agreement by which I was selected to each owner and operator of the source and of each CSAPR NO_X Ozone Season Group 2 unit at the source; and CSAPR NO_X Ozone Season Group 2 allowances and proceeds of transactions involving CSAPR NO_X Ozone Season Group 2 allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of CSAPR NO_X Ozone Season Group 2 allowances by contract, CSAPR NO_X Ozone Season Group 2 allowances and proceeds of transactions involving CSAPR NO_X Ozone Season Group 2 allowances will be deemed to be held or distributed in accordance with the contract."

(5) The signature of the designated representative and any alternate designated representative and the dates signed.

(b) Unless otherwise required by the Administrator, documents of agreement referred to in the certificate of representation shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(c) A certificate of representation under this section or §97.516 that complies with the provisions of paragraph (a) of this section except that it contains the phrase "TR NO_X Ozone Season" in place of the phrase "CSAPR NO_X Ozone Season Group 2" in the required certification statements will be considered a complete certificate of representation under this section, and the certification statements included in such certificate of representation will be interpreted for purposes of this subpart as if the phrase "CSAPR NO_X Ozone Season Group 2" appeared in place of the phrase "TR NO_X Ozone Season".

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§97.817 Objections concerning designated representative and alternate designated representative.

(a) Once a complete certificate of representation under §97.816 has been submitted and received, the Administrator will rely on the certificate of representation unless and until a superseding complete certificate of representation under §97.816 is received by the Administrator.

(b) Except as provided in paragraph (a) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission, of a designated representative or alternate designated representative shall affect any representation, action, inaction, or submission of the designated representative or alternate designated representative or the finality of any decision or order by the Administrator under the CSAPR NO_X Ozone Season Group 2 Trading Program.

(c) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any designated representative or alternate designated representative, including private legal disputes concerning the proceeds of CSAPR NO_X Ozone Season Group 2 allowance transfers.

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§97.818 Delegation by designated representative and alternate designated representative.

(a) A designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(b) An alternate designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(c) In order to delegate authority to a natural person to make an electronic submission to the Administrator in accordance with paragraph (a) or (b) of this section, the designated representative or alternate designated representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(1) The name, address, email address, telephone number, and facsimile transmission number (if any) of such designated representative or alternate designated representative;

(2) The name, address, email address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to in this section as an "agent");

(3) For each such natural person, a list of the type or types of electronic submissions under paragraph (a) or (b) of this section for which authority is delegated to him or her; and

(4) The following certification statements by such designated representative or alternate designated representative:

(i) "I agree that any electronic submission to the Administrator that is made by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am a designated representative or alternate designated representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 40 CFR 97.818(d) shall be deemed to be an electronic submission by me."

(ii) "Until this notice of delegation is superseded by another notice of delegation under 40 CFR 97.818(d), I agree to maintain an email account and to notify the Administrator immediately of any change in my email address unless all delegation of authority by me under 40 CFR 97.818 is terminated.".

(d) A notice of delegation submitted under paragraph (c) of this section shall be effective, with regard to the designated representative or alternate designated representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such designated representative or alternate designated representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(e) Any electronic submission covered by the certification in paragraph (c)(4)(i) of this section and made in accordance with a notice of delegation effective under paragraph (d) of this section shall be deemed to be an electronic submission by the designated representative or alternate designated representative submitting such notice of delegation.

(f) A notice of delegation submitted under paragraph (c) of this section or §97.518(c) that complies with the provisions of paragraph (c) of this section except that it contains the terms "40 CFR 97.518(d)" and "40 CFR 97.518" in place of the terms "40 CFR 97.818(d)" and "40 CFR 97.818", respectively, in the required certification statements will be considered a valid notice of delegation submitted under paragraph (c) of this section, and the certification statements included in such notice of delegation will be interpreted for purposes of this subpart as if the terms "40 CFR 97.818(d)" and "40 CFR 97.818" appeared in place of the terms "40 CFR 97.518(d)" and "40 CFR 97.518", respectively.

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§97.819 [Reserved]

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§97.820 Establishment of compliance accounts, assurance accounts, and general accounts.

(a) *Compliance accounts.* Upon receipt of a complete certificate of representation under §97.816, the Administrator will establish a compliance account for the CSAPR NO_X Ozone Season Group 2 source for which the certificate of representation was submitted, unless the source already has a compliance account. The designated representative and any alternate designated representative of the source shall be the authorized account representative and the alternate authorized account representative respectively of the compliance account.

(b) *Assurance accounts.* The Administrator will establish assurance accounts for certain owners and operators and States in accordance with §97.825(b)(3).

(c) *General accounts*—(1) *Application for general account.* (i) Any person may apply to open a general account, for the purpose of holding and transferring CSAPR NO_X Ozone Season Group 2 allowances, by submitting to the Administrator a complete application for a general account. Such application shall designate one and only one authorized account representative and may designate one and only one alternate authorized account representative who may act on behalf of the authorized account representative.

(A) The authorized account representative and alternate authorized account representative shall be selected by an agreement binding on the persons who have an ownership interest with respect to CSAPR NO_X Ozone Season Group 2 allowances held in the general account.

(B) The agreement by which the alternate authorized account representative is selected shall include a procedure for authorizing the alternate authorized account representative to act in lieu of the authorized account representative.

(ii) A complete application for a general account shall include the following elements in a format prescribed by the Administrator:

(A) Name, mailing address, email address (if any), telephone number, and facsimile transmission number (if any) of the authorized account representative and any alternate authorized account representative;

(B) An identifying name for the general account;

(C) A list of all persons subject to a binding agreement for the authorized account representative and any alternate authorized account representative to represent their ownership interest with respect to the CSAPR NO_X Ozone Season Group 2 allowances held in the general account;

(D) The following certification statement by the authorized account representative and any alternate authorized account representative: "I certify that I was selected as the authorized account representative or the alternate authorized account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to CSAPR NO_X Ozone Season Group 2 allowances held in the general account. I certify that I have all the necessary authority to carry out my duties and responsibilities under the CSAPR NO_X Ozone Season Group 2 Trading Program on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the Administrator regarding the general account."

(E) The signature of the authorized account representative and any alternate authorized account representative and the dates signed.

(iii) Unless otherwise required by the Administrator, documents of agreement referred to in the application for a general account shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(iv) An application for a general account under paragraph (c)(1) of this section or §97.520(c)(1) that complies with the provisions of paragraph (c)(1) of this section except that it contains the phrase "TR NO_X Ozone Season" in place of the phrase "CSAPR NO_X Ozone Season Group 2" in the required certification statement will be considered a complete application for a general account under paragraph (c)(1) of this section, and the certification statement included in such application for a general account will be interpreted for purposes of this subpart as if the phrase "CSAPR NO_X Ozone Season Group 2" appeared in place of the phrase "TR NO_X Ozone Season".

(2) *Authorization of authorized account representative and alternate authorized account representative.* (i) Upon receipt by the Administrator of a complete application for a general account under paragraph (c)(1) of this section, the Administrator will establish a general account for the person or persons for whom the application is submitted, and upon and after such receipt by the Administrator:

(A) The authorized account representative of the general account shall be authorized and shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each person who has an ownership interest with respect to CSAPR NO_X Ozone Season Group 2 allowances held in the general account in all matters pertaining to the CSAPR NO_X Ozone Season Group 2 Trading Program, notwithstanding any agreement between the authorized account representative and such person.

(B) Any alternate authorized account representative shall be authorized, and any representation, action, inaction, or submission by any alternate authorized account representative shall be deemed to be a representation, action, inaction, or submission by the authorized account representative.

(C) Each person who has an ownership interest with respect to CSAPR NO_X Ozone Season Group 2 allowances held in the general account shall be bound by any decision or order issued to the authorized account representative or alternate authorized account representative by the Administrator regarding the general account.

(ii) Except as provided in paragraph (c)(5) of this section concerning delegation of authority to make submissions, each submission concerning the general account shall be made, signed, and certified by the authorized account representative or any alternate authorized account representative for the persons having an ownership interest with respect to CSAPR NO_X Ozone Season Group 2 allowances held in the general account. Each such submission shall include the following certification statement by the authorized account representative or any alternate authorized account representative: "I am authorized to make this submission on behalf of the persons having an ownership interest with respect to the CSAPR NO_X Ozone Season Group 2 allowances held in the general account. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(iii) Except in this section, whenever the term "authorized account representative" is used in this subpart, the term shall be construed to include the authorized account representative or any alternate authorized account representative.

(iv) A certification statement submitted in accordance with paragraph (c)(2)(ii) of this section that contains the phrase "TR NO_X Ozone Season" will be interpreted for purposes of this subpart as if the phrase "CSAPR NO_X Ozone Season Group 2" appeared in place of the phrase "TR NO_X Ozone Season".

(3) *Changing authorized account representative and alternate authorized account representative; changes in persons with ownership interest.* (i) The authorized account representative of a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (c)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new authorized account representative and the persons with an ownership interest with respect to the CSAPR NO_X Ozone Season Group 2 allowances in the general account.

(ii) The alternate authorized account representative of a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (c)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new alternate authorized account representative, the authorized account representative, and the persons with an ownership interest with respect to the CSAPR NO_X Ozone Season Group 2 allowances in the general account.

(iii)(A) In the event a person having an ownership interest with respect to CSAPR NO_X Ozone Season Group 2 allowances in the general account is not included in the list of such persons in the application for a general account, such person shall be deemed to be subject to and bound by the application for a general account, the representation, actions, inactions, and submissions of the authorized account representative and any alternate authorized account representative of the account, and the decisions and orders of the Administrator, as if the person were included in such list.

(B) Within 30 days after any change in the persons having an ownership interest with respect to NO_X Ozone Season Group 2 allowances in the general account, including the addition or removal of a person, the authorized account representative or any alternate authorized account representative shall submit a revision to the application for a general account amending the list of persons having an ownership interest with respect to the CSAPR NO_X Ozone Season Group 2 allowances in the general account to include the change.

(4) *Objections concerning authorized account representative and alternate authorized account representative.* (i) Once a complete application for a general account under paragraph (c)(1) of this section has been submitted and received, the Administrator will rely on the application unless and until a superseding complete application for a general account under paragraph (c)(1) of this section is received by the Administrator.

(ii) Except as provided in paragraph (c)(4)(i) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative of a general account shall affect any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative or the finality of any decision or order by the Administrator under the CSAPR NO_X Ozone Season Group 2 Trading Program.

(iii) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative of a general account, including private legal disputes concerning the proceeds of CSAPR NO_X Ozone Season Group 2 allowance transfers.

(5) *Delegation by authorized account representative and alternate authorized account representative.* (i) An authorized account representative of a general account may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(ii) An alternate authorized account representative of a general account may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(iii) In order to delegate authority to a natural person to make an electronic submission to the Administrator in accordance with paragraph (c)(5)(i) or (ii) of this section, the authorized account representative or alternate authorized account representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(A) The name, address, email address, telephone number, and facsimile transmission number (if any) of such authorized account representative or alternate authorized account representative;

(B) The name, address, email address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to in this section as an "agent");

(C) For each such natural person, a list of the type or types of electronic submissions under paragraph (c)(5)(i) or (ii) of this section for which authority is delegated to him or her;

(D) The following certification statement by such authorized account representative or alternate authorized account representative: "I agree that any electronic submission to the Administrator that is made by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am an authorized account representative or alternate authorized account representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 40 CFR 97.820(c)(5)(iv) shall be deemed to be an electronic submission by me."; and

(E) The following certification statement by such authorized account representative or alternate authorized account representative: "Until this notice of delegation is superseded by another notice of delegation under 40 CFR 97.820(c)(5)(iv), I agree to maintain an email account and to notify the Administrator immediately of any change in my email address unless all delegation of authority by me under 40 CFR 97.820(c)(5) is terminated.".

(iv) A notice of delegation submitted under paragraph (c)(5)(iii) of this section shall be effective, with regard to the authorized account representative or alternate authorized account representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such authorized account representative or alternate authorized account representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(v) Any electronic submission covered by the certification in paragraph (c)(5)(iii)(D) of this section and made in accordance with a notice of delegation effective under paragraph (c)(5)(iv) of this section shall be deemed to be an electronic submission by the authorized account representative or alternate authorized account representative submitting such notice of delegation.

(vi) A notice of delegation submitted under paragraph (c)(5)(iii) of this section or §97.520(c)(5)(iii) that complies with the provisions of paragraph (c)(5)(iii) of this section except that it contains the terms "40 CFR 97.520(c)(5)(iv)" and "40 CFR 97.520(c)(5)" in place of the terms "40 CFR 97.820(c)(5)(iv)" and "40 CFR 97.820(c)(5)", respectively, in the required certification statements will be considered a valid notice of delegation submitted under paragraph (c)(5)(iii) of this section, and the certification statements included in such notice of delegation will be interpreted for purposes of this subpart as if the terms "40 CFR 97.820(c)(5)(iv)" and "40 CFR 97.820(c)(5)" appeared in place of the terms "40 CFR 97.520(c)(5)(iv)" and "40 CFR 97.520(c)(5)", respectively.

(6) *Closing a general account.* (i) The authorized account representative or alternate authorized account representative of a general account may submit to the Administrator a request to close the account. Such request shall include a correctly submitted CSAPR NO_X Ozone Season Group 2 allowance transfer under §97.822 for any CSAPR NO_X Ozone Season Group 2 allowances in the account to one or more other Allowance Management System accounts.

(ii) If a general account has no CSAPR NO_X Ozone Season Group 2 allowance transfers to or from the account for a 12-month period or longer and does not contain any CSAPR NO_X Ozone Season Group 2 allowances, the Administrator may notify the authorized account representative for the account that the account will be closed after 30 days after the notice is sent. The account will be closed after the 30-day period unless, before the end of the 30-day period, the Administrator receives a correctly submitted CSAPR NO_X Ozone Season Group 2 allowance transfer under §97.822 to the account or a statement submitted by the authorized account representative or alternate authorized account representative demonstrating to the satisfaction of the Administrator good cause as to why the account should not be closed.

(d) *Account identification.* The Administrator will assign a unique identifying number to each account established under paragraph (a), (b), or (c) of this section.

(e) *Responsibilities of authorized account representative and alternate authorized account representative.* After the establishment of a compliance account or general account, the Administrator will accept or act on a submission pertaining to the account, including, but not limited to, submissions concerning the deduction or transfer of CSAPR NO_X Ozone Season Group 2 allowances in the account, only if the submission has been made, signed, and certified in accordance with §§97.814(a) and 97.818 or paragraphs (c)(2)(ii) and (c)(5) of this section.

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§97.821 Recordation of CSAPR NO_X Ozone Season Group 2 allowance allocations and auction results.

(a) By January 9, 2017, the Administrator will record in each CSAPR NO_X Ozone Season Group 2 source's compliance account the CSAPR NO_X Ozone Season Group 2 allowances allocated to the CSAPR NO_X Ozone Season Group 2 units at the source in accordance with §97.811(a) for the control period in 2017.

(b) By January 9, 2017, the Administrator will record in each CSAPR NO_X Ozone Season Group 2 source's compliance account the CSAPR NO_X Ozone Season Group 2 allowances allocated to the CSAPR NO_X Ozone Season Group 2 units at the source in accordance with §97.811(a) for the control period in 2018, unless the State in which the source is located notifies the Administrator in writing by December 27, 2016 of the State's intent to submit to the Administrator a complete SIP revision by April 1, 2017 meeting the requirements of §52.38(b)(7)(i) through (iv) of this chapter.

(1) If, by April 1, 2017 the State does not submit to the Administrator such complete SIP revision, the Administrator will record by April 15, 2017 in each CSAPR NO_X Ozone Season Group 2 source's compliance account the CSAPR NO_X Ozone Season Group 2 allowances allocated to the CSAPR NO_X Ozone Season Group 2 units at the source in accordance with §97.811(a) for the control period in 2018.

(2) If the State submits to the Administrator by April 1, 2017 and the Administrator approves by October 1, 2017 such complete SIP revision, the Administrator will record by October 1, 2017 in each CSAPR NO_X Ozone Season Group 2 source's compliance account the CSAPR NO_X Ozone Season Group 2 allowances allocated to the CSAPR NO_X Ozone Season Group 2 units at the source as provided in such approved, complete SIP revision for the control period in 2018.

(3) If the State submits to the Administrator by April 1, 2017 and the Administrator does not approve by October 1, 2017 such complete SIP revision, the Administrator will record by October 1, 2017 in each CSAPR NO_X Ozone Season Group 2 source's compliance account the CSAPR NO_X Ozone Season Group 2 allowances allocated to the CSAPR NO_X Ozone Season Group 2 units at the source in accordance with §97.811(a) for the control period in 2018.

(c) By July 1, 2018, the Administrator will record in each CSAPR NO_X Ozone Season Group 2 source's compliance account the CSAPR NO_X Ozone Season Group 2 allowances allocated to the CSAPR NO_X Ozone Season Group 2 units at the source, or in each appropriate Allowance Management System account the CSAPR NO_X Ozone Season Group 2 allowances auctioned to CSAPR NO_X Ozone Season Group 2 units, in accordance with §97.811(a), or with a SIP revision approved under §52.38(b)(6), (8), or (9) of this chapter, for the control periods in 2019 and 2020.

(d) By July 1, 2019, the Administrator will record in each CSAPR NO_X Ozone Season Group 2 source's compliance account the CSAPR NO_X Ozone Season Group 2 allowances allocated to the CSAPR NO_X Ozone Season Group 2 units at the source, or in each appropriate Allowance Management System account the CSAPR NO_X Ozone Season Group 2 allowances auctioned to CSAPR NO_X Ozone Season Group 2 units, in accordance with §97.811(a), or with a SIP revision approved under §52.38(b)(6), (8), or (9) of this chapter, for the control periods in 2021 and 2022.

(e) By July 1, 2020, the Administrator will record in each CSAPR NO_X Ozone Season Group 2 source's compliance account the CSAPR NO_X Ozone Season Group 2 allowances allocated to the CSAPR NO_X Ozone Season Group 2 units at the source, or in each appropriate Allowance Management System account the CSAPR NO_X Ozone Season Group 2 allowances auctioned to CSAPR NO_X Ozone Season Group 2 units, in accordance with §97.811(a), or with a SIP revision approved under §52.38(b)(6), (8), or (9) of this chapter, for the control periods in 2023 and 2024.

(f) By July 1, 2021 and July 1 of each year thereafter, the Administrator will record in each CSAPR NO_X Ozone Season Group 2 source's compliance account the CSAPR NO_X Ozone Season Group 2 allowances allocated to the CSAPR NO_X Ozone Season Group 2 units at the source, or in each appropriate Allowance Management System account the CSAPR NO_X Ozone Season Group 2 allowances auctioned to CSAPR NO_X Ozone Season Group 2 units, in accordance with §97.811(a), or with a SIP revision approved under §52.38(b)(6), (8), or (9) of this chapter, for the control period in the fourth year after the year of the applicable recordation deadline under this paragraph.

(g) By August 1, 2017 and August 1 of each year thereafter, the Administrator will record in each CSAPR NO_X Ozone Season Group 2 source's compliance account the CSAPR NO_X Ozone Season Group 2 allowances allocated to the CSAPR NO_X Ozone Season Group 2 units at the source, or in each appropriate Allowance Management System account the CSAPR NO_X Ozone Season Group 2 allowances auctioned to CSAPR NO_X Ozone Season Group 2 units, in accordance with §97.812(a)(2) through (8) and (12), or with a SIP revision approved under §52.38(b)(6), (8), or (9) of this chapter, for the control period in the year of the applicable recordation deadline under this paragraph.

(h) By August 1, 2017 and August 1 of each year thereafter, the Administrator will record in each CSAPR NO_X Ozone Season Group 2 source's compliance account the CSAPR NO_X Ozone Season Group 2 allowances allocated to the CSAPR NO_X Ozone Season Group 2 units at the source in accordance with §97.812(b)(2) through (8) and (12) for the control period in the year of the applicable recordation deadline under this paragraph.

(i) By February 15, 2018 and February 15 of each year thereafter, the Administrator will record in each CSAPR NO_X Ozone Season Group 2 source's compliance account the CSAPR NO_X Ozone Season Group 2 allowances allocated to the CSAPR NO_X Ozone Season Group 2 units at the source in accordance with §97.812(a)(9) through (12) for the control period in the year before the year of the applicable recordation deadline under this paragraph.

(j) By February 15, 2018 and February 15 of each year thereafter, the Administrator will record in each CSAPR NO_X Ozone Season Group 2 source's compliance account the CSAPR NO_X Ozone Season Group 2 allowances allocated to the CSAPR NO_X Ozone Season Group 2 units at the source in accordance with §97.812(b)(9) through (12) for the control period in the year before the year of the applicable recordation deadline under this paragraph.

(k) By the date 15 days after the date on which any allocation or auction results, other than an allocation or auction results described in paragraphs (a) through (j) of this section, of CSAPR NO_X Ozone Season Group 2 allowances to a recipient is made by or are submitted to the Administrator in accordance with §97.811 or §97.812 or with a SIP revision approved under §52.38(b)(6), (8), or (9) of this chapter, the Administrator will record such allocation or auction results in the appropriate Allowance Management System account.

(l) When recording the allocation or auction of CSAPR NO_X Ozone Season Group 2 allowances to a CSAPR NO_X Ozone Season Group 2 unit or other entity in an Allowance Management System account, the Administrator will assign each CSAPR NO_X Ozone Season Group 2 allowance a unique identification number that will include digits identifying the year of the control period for which the CSAPR NO_X Ozone Season Group 2 allowance is allocated or auctioned.

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§97.822 Submission of CSAPR NO_X Ozone Season Group 2 allowance transfers.

(a) An authorized account representative seeking recordation of a CSAPR NO_X Ozone Season Group 2 allowance transfer shall submit the transfer to the Administrator.

(b) A CSAPR NO_X Ozone Season Group 2 allowance transfer shall be correctly submitted if:

(1) The transfer includes the following elements, in a format prescribed by the Administrator:

(i) The account numbers established by the Administrator for both the transferor and transferee accounts;

(ii) The serial number of each CSAPR NO_X Ozone Season Group 2 allowance that is in the transferor account and is to be transferred; and

(iii) The name and signature of the authorized account representative of the transferor account and the date signed; and

(2) When the Administrator attempts to record the transfer, the transferor account includes each CSAPR NO_X Ozone Season Group 2 allowance identified by serial number in the transfer.

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§97.823 Recordation of CSAPR NO_X Ozone Season Group 2 allowance transfers.

(a) Within 5 business days (except as provided in paragraph (b) of this section) of receiving a CSAPR NO_X Ozone Season Group 2 allowance transfer that is correctly submitted under §97.822, the Administrator will record a CSAPR NO_X Ozone Season Group 2 allowance transfer by moving each CSAPR NO_X Ozone Season Group 2 allowance from the transferor account to the transferee account as specified in the transfer.

(b) A CSAPR NO_X Ozone Season Group 2 allowance transfer to or from a compliance account that is submitted for recordation after the allowance transfer deadline for a control period and that includes any CSAPR NO_X Ozone Season Group 2 allowances allocated or auctioned for any control period before such allowance transfer deadline will not be recorded until after the Administrator completes the deductions from such compliance account under §97.824 for the control period immediately before such allowance transfer deadline.

(c) Where a CSAPR NO_X Ozone Season Group 2 allowance transfer is not correctly submitted under §97.822, the Administrator will not record such transfer.

(d) Within 5 business days of recordation of a CSAPR NO_X Ozone Season Group 2 allowance transfer under paragraphs (a) and (b) of the section, the Administrator will notify the authorized account representatives of both the transferor and transferee accounts.

(e) Within 10 business days of receipt of a CSAPR NO_X Ozone Season Group 2 allowance transfer that is not correctly submitted under §97.822, the Administrator will notify the authorized account representatives of both accounts subject to the transfer of:

(1) A decision not to record the transfer, and

(2) The reasons for such non-recordation.

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§97.824 Compliance with CSAPR NO_X Ozone Season Group 2 emissions limitation.

(a) *Availability for deduction for compliance.* CSAPR NO_X Ozone Season Group 2 allowances are available to be deducted for compliance with a source's CSAPR NO_X Ozone Season Group 2 emissions limitation for a control period in a given year only if the CSAPR NO_X Ozone Season Group 2 allowances:

(1) Were allocated or auctioned for such control period or a control period in a prior year; and

(2) Are held in the source's compliance account as of the allowance transfer deadline for such control period.

(b) *Deductions for compliance.* After the recordation, in accordance with §97.823, of CSAPR NO_X Ozone Season Group 2 allowance transfers submitted by the allowance transfer deadline for a control period in a given year, the Administrator will deduct from each source's compliance account CSAPR NO_X Ozone Season Group 2 allowances available under paragraph (a) of this section in order to determine whether the source meets the CSAPR NO_X Ozone Season Group 2 emissions limitation for such control period, as follows:

(1) Until the amount of CSAPR NO_X Ozone Season Group 2 allowances deducted equals the number of tons of total NO_X emissions from all CSAPR NO_X Ozone Season Group 2 units at the source for such control period; or

(2) If there are insufficient CSAPR NO_X Ozone Season Group 2 allowances to complete the deductions in paragraph (b)(1) of this section, until no more CSAPR NO_X Ozone Season Group 2 allowances available under paragraph (a) of this section remain in the compliance account.

(c)(1) *Identification of CSAPR NO_X Ozone Season Group 2 allowances by serial number.* The authorized account representative for a source's compliance account may request that specific CSAPR NO_X Ozone Season Group 2 allowances, identified by serial number, in the compliance account be deducted for emissions or excess emissions for a control period in a given year in accordance with paragraph (b) or (d) of this section. In order to be complete, such request shall be submitted to the Administrator by the allowance transfer deadline for such control period and include, in a format prescribed by the Administrator, the identification of the CSAPR NO_X Ozone Season Group 2 source and the appropriate serial numbers.

(2) *First-in, first-out.* The Administrator will deduct CSAPR NO_X Ozone Season Group 2 allowances under paragraph (b) or (d) of this section from the source's compliance account in accordance with a complete request under paragraph (c)(1) of this

section or, in the absence of such request or in the case of identification of an insufficient amount of CSAPR NO_X Ozone Season Group 2 allowances in such request, on a first-in, first-out accounting basis in the following order:

(i) Any CSAPR NO_X Ozone Season Group 2 allowances that were recorded in the compliance account pursuant to §97.821 and not transferred out of the compliance account, in the order of recordation; and then

(ii) Any other CSAPR NO_X Ozone Season Group 2 allowances that were transferred to and recorded in the compliance account pursuant to this subpart or that were recorded in the compliance account pursuant to §97.526(c), in the order of recordation.

(d) *Deductions for excess emissions.* After making the deductions for compliance under paragraph (b) of this section for a control period in a year in which the CSAPR NO_X Ozone Season Group 2 source has excess emissions, the Administrator will deduct from the source's compliance account an amount of CSAPR NO_X Ozone Season Group 2 allowances, allocated or auctioned for a control period in a prior year or the control period in the year of the excess emissions or in the immediately following year, equal to two times the number of tons of the source's excess emissions.

(e) *Recordation of deductions.* The Administrator will record in the appropriate compliance account all deductions from such an account under paragraphs (b) and (d) of this section.

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§97.825 Compliance with CSAPR NO_X Ozone Season Group 2 assurance provisions.

(a) *Availability for deduction.* CSAPR NO_X Ozone Season Group 2 allowances are available to be deducted for compliance with the CSAPR NO_X Ozone Season Group 2 assurance provisions for a control period in a given year by the owners and operators of a group of one or more base CSAPR NO_X Ozone Season Group 2 sources and units in a State (and Indian country within the borders of such State) only if the CSAPR NO_X Ozone Season Group 2 allowances:

(1) Were allocated or auctioned for a control period in a prior year or the control period in the given year or in the immediately following year; and

(2) Are held in the assurance account, established by the Administrator for such owners and operators of such group of base CSAPR NO_X Ozone Season Group 2 sources and units in such State (and Indian country within the borders of such State) under paragraph (b)(3) of this section, as of the deadline established in paragraph (b)(4) of this section.

(b) *Deductions for compliance.* The Administrator will deduct CSAPR NO_X Ozone Season Group 2 allowances available under paragraph (a) of this section for compliance with the CSAPR NO_X Ozone Season Group 2 assurance provisions for a State for a control period in a given year in accordance with the following procedures:

(1) By June 1, 2018 and June 1 of each year thereafter, the Administrator will:

(i) Calculate, for each State (and Indian country within the borders of such State), the total NO_X emissions from all base CSAPR NO_X Ozone Season Group 2 units at base CSAPR NO_X Ozone Season Group 2 sources in the State (and Indian country within the borders of such State) during the control period in the year before the year of this calculation deadline and the amount, if any, by which such total NO_X emissions exceed the State assurance level as described in §97.806(c)(2)(iii); and

(ii) Promulgate a notice of data availability of the results of the calculations required in paragraph (b)(1)(i) of this section, including separate calculations of the NO_X emissions from each base CSAPR NO_X Ozone Season Group 2 source.

(2) For each notice of data availability required in paragraph (b)(1)(ii) of this section and for any State (and Indian country within the borders of such State) identified in such notice as having base CSAPR NO_X Ozone Season Group 2 units with total NO_X emissions exceeding the State assurance level for a control period in a given year, as described in §97.806(c)(2)(iii):

(i) By July 1 immediately after the promulgation of such notice, the designated representative of each base CSAPR NO_X Ozone Season Group 2 source in each such State (and Indian country within the borders of such State) shall submit a statement, in a format prescribed by the Administrator, providing for each base CSAPR NO_X Ozone Season Group 2 unit (if any) at the source that operates during, but is not allocated an amount of CSAPR NO_X Ozone Season Group 2 allowances for, such control period, the unit's allowable NO_X emission rate for such control period and, if such rate is expressed in lb per mmBtu, the unit's heat rate.

(ii) By August 1 immediately after the promulgation of such notice, the Administrator will calculate, for each such State (and Indian country within the borders of such State) and such control period and each common designated representative for such control period for a group of one or more base CSAPR NO_X Ozone Season Group 2 sources and units in the State (and Indian country within the borders of such State), the common designated representative's share of the total NO_X emissions from all base CSAPR NO_X Ozone Season Group 2 units at base CSAPR NO_X Ozone Season Group 2 sources in the State (and Indian country within the borders of such State), the common designated representative's assurance level, and the amount (if any) of CSAPR NO_X Ozone Season Group 2 allowances that the owners and operators of such group of sources and units must hold in accordance with the calculation formula in §97.806(c)(2)(i) and will promulgate a notice of data availability of the results of these calculations.

(iii) The Administrator will provide an opportunity for submission of objections to the calculations referenced by the notice of data availability required in paragraph (b)(2)(ii) of this section and the calculations referenced by the relevant notice of data availability required in paragraph (b)(1)(ii) of this section.

(A) Objections shall be submitted by the deadline specified in such notice and shall be limited to addressing whether the calculations referenced in the relevant notice required under paragraph (b)(1)(ii) of this section and referenced in the notice required under paragraph (b)(2)(ii) of this section are in accordance with §97.806(c)(2)(iii), §§97.806(b) and 97.830 through 97.835, the definitions of “common designated representative”, “common designated representative's assurance level”, and “common designated representative's share” in §97.802, and the calculation formula in §97.806(c)(2)(i).

(B) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(2)(iii)(A) of this section. By October 1 immediately after the promulgation of such notice, the Administrator will promulgate a notice of data availability of the calculations incorporating any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(2)(iii)(A) of this section.

(3) For any State (and Indian country within the borders of such State) referenced in each notice of data availability required in paragraph (b)(2)(iii)(B) of this section as having base CSAPR NO_X Ozone Season Group 2 units with total NO_X emissions exceeding the State assurance level for a control period in a given year, the Administrator will establish one assurance account for each set of owners and operators referenced, in the notice of data availability required under paragraph (b)(2)(iii)(B) of this section, as all of the owners and operators of a group of base CSAPR NO_X Ozone Season Group 2 sources and units in the State (and Indian country within the borders of such State) having a common designated representative for such control period and as being required to hold CSAPR NO_X Ozone Season Group 2 allowances.

(4)(i) As of midnight of November 1 immediately after the promulgation of each notice of data availability required in paragraph (b)(2)(iii)(B) of this section, the owners and operators described in paragraph (b)(3) of this section shall hold in the assurance account established for them and for the appropriate base CSAPR NO_X Ozone Season Group 2 sources, base CSAPR NO_X Ozone Season Group 2 units, and State (and Indian country within the borders of such State) under paragraph (b)(3) of this section a total amount of CSAPR NO_X Ozone Season Group 2 allowances, available for deduction under paragraph (a) of this section, equal to the amount such owners and operators are required to hold with regard to such sources, units and State (and Indian country within the borders of such State) as calculated by the Administrator and referenced in such notice.

(ii) Notwithstanding the allowance-holding deadline specified in paragraph (b)(4)(i) of this section, if November 1 is not a business day, then such allowance-holding deadline shall be midnight of the first business day thereafter.

(5) After November 1 (or the date described in paragraph (b)(4)(ii) of this section) immediately after the promulgation of each notice of data availability required in paragraph (b)(2)(iii)(B) of this section and after the recordation, in accordance with §97.823, of CSAPR NO_X Ozone Season Group 2 allowance transfers submitted by midnight of such date, the Administrator will determine whether the owners and operators described in paragraph (b)(3) of this section hold, in the assurance account for the appropriate base CSAPR NO_X Ozone Season Group 2 sources, base CSAPR NO_X Ozone Season Group 2 units, and State (and Indian country within the borders of such State) established under paragraph (b)(3) of this section, the amount of CSAPR NO_X Ozone Season Group 2 allowances available under paragraph (a) of this section that the owners and operators are required to hold with regard to such sources, units, and State (and Indian country within the borders of such State) as calculated by the Administrator and referenced in the notice required in paragraph (b)(2)(iii)(B) of this section.

(6) Notwithstanding any other provision of this subpart and any revision, made by or submitted to the Administrator after the promulgation of the notice of data availability required in paragraph (b)(2)(iii)(B) of this section for a control period in a given year, of any data used in making the calculations referenced in such notice, the amounts of CSAPR NO_X Ozone Season Group 2 allowances that the owners and operators are required to hold in accordance with §97.806(c)(2)(i) for such control period shall continue to be such amounts as calculated by the Administrator and referenced in such notice required in paragraph (b)(2)(iii)(B) of this section, except as follows:

(i) If any such data are revised by the Administrator as a result of a decision in or settlement of litigation concerning such data on appeal under part 78 of this chapter of such notice, or on appeal under section 307 of the Clean Air Act of a decision rendered under part 78 of this chapter on appeal of such notice, then the Administrator will use the data as so revised to recalculate the amounts of CSAPR NO_X Ozone Season Group 2 allowances that owners and operators are required to hold in accordance with the calculation formula in §97.806(c)(2)(i) for such control period with regard to the base CSAPR NO_X Ozone Season Group 2 sources, base CSAPR NO_X Ozone Season Group 2 units, and State (and Indian country within the borders of such State) involved, provided that such litigation under part 78 of this chapter, or the proceeding under part 78 of this chapter that resulted in the decision appealed in such litigation under section 307 of the Clean Air Act, was initiated no later than 30 days after promulgation of such notice required in paragraph (b)(2)(iii)(B) of this section.

(ii) If any such data are revised by the owners and operators of a base CSAPR NO_X Ozone Season Group 2 source and base CSAPR NO_X Ozone Season Group 2 unit whose designated representative submitted such data under paragraph (b)(2)(i) of this section, as a result of a decision in or settlement of litigation concerning such submission, then the Administrator will use the data as so revised to recalculate the amounts of CSAPR NO_X Ozone Season Group 2 allowances that owners and operators are required to hold in accordance with the calculation formula in §97.806(c)(2)(i) for such control period with regard to the base CSAPR NO_X Ozone Season Group 2 sources, base CSAPR NO_X Ozone Season Group 2 units, and State (and Indian country within the borders of such State) involved, provided that such litigation was initiated no later than 30 days after promulgation of such notice required in paragraph (b)(2)(iii)(B) of this section.

(iii) If the revised data are used to recalculate, in accordance with paragraphs (b)(6)(i) and (ii) of this section, the amount of CSAPR NO_X Ozone Season Group 2 allowances that the owners and operators are required to hold for such control period with regard to the base CSAPR NO_X Ozone Season Group 2 sources, base CSAPR NO_X Ozone Season Group 2 units, and State (and Indian country within the borders of such State) involved—

(A) Where the amount of CSAPR NO_X Ozone Season Group 2 allowances that the owners and operators are required to hold increases as a result of the use of all such revised data, the Administrator will establish a new, reasonable deadline on which the owners and operators shall hold the additional amount of CSAPR NO_X Ozone Season Group 2 allowances in the assurance account established by the Administrator for the appropriate base CSAPR NO_X Ozone Season Group 2 sources, base CSAPR NO_X Ozone Season Group 2 units, and State (and Indian country within the borders of such State) under paragraph (b)(3) of this section. The owners' and operators' failure to hold such additional amount, as required, before the new deadline shall not be a violation of the Clean Air Act. The owners' and operators' failure to hold such additional amount, as required, as of the new deadline shall be a violation of the Clean Air Act. Each CSAPR NO_X Ozone Season Group 2 allowance that the owners and operators fail to hold as required as of the new deadline, and each day in such control period, shall be a separate violation of the Clean Air Act.

(B) For the owners and operators for which the amount of CSAPR NO_X Ozone Season Group 2 allowances required to be held decreases as a result of the use of all such revised data, the Administrator will record, in all accounts from which CSAPR NO_X Ozone Season Group 2 allowances were transferred by such owners and operators for such control period to the assurance account established by the Administrator for the appropriate base CSAPR NO_X Ozone Season Group 2 sources, base CSAPR NO_X Ozone Season Group 2 units, and State (and Indian country within the borders of such State) under paragraph (b)(3) of this section, a total amount of the CSAPR NO_X Ozone Season Group 2 allowances held in such assurance account equal to the amount of the decrease. If CSAPR NO_X Ozone Season Group 2 allowances were transferred to such assurance account from more than one account, the amount of CSAPR NO_X Ozone Season Group 2 allowances recorded in each such transferor account will be in proportion to the percentage of the total amount of CSAPR NO_X Ozone Season Group 2 allowances transferred to such assurance account for such control period from such transferor account.

(C) Each CSAPR NO_X Ozone Season Group 2 allowance held under paragraph (b)(6)(iii)(A) of this section as a result of recalculation of requirements under the CSAPR NO_X Ozone Season Group 2 assurance provisions for such control period must be a CSAPR NO_X Ozone Season Group 2 allowance allocated for a control period in a year before or the year immediately following, or in the same year as, the year of such control period.

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§97.826 Banking.

(a) A CSAPR NO_X Ozone Season Group 2 allowance may be banked for future use or transfer in a compliance account or a general account in accordance with paragraph (b) of this section.

(b) Any CSAPR NO_X Ozone Season Group 2 allowance that is held in a compliance account or a general account will remain in such account unless and until the CSAPR NO_X Ozone Season Group 2 allowance is deducted or transferred under §97.811(c), §97.823, §97.824, §97.825, §97.827, or §97.828.

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§97.827 Account error.

The Administrator may, at his or her sole discretion and on his or her own motion, correct any error in any Allowance Management System account. Within 10 business days of making such correction, the Administrator will notify the authorized account representative for the account.

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§97.828 Administrator's action on submissions.

(a) The Administrator may review and conduct independent audits concerning any submission under the CSAPR NO_X Ozone Season Group 2 Trading Program and make appropriate adjustments of the information in the submission.

(b) The Administrator may deduct CSAPR NO_X Ozone Season Group 2 allowances from or transfer CSAPR NO_X Ozone Season Group 2 allowances to a compliance account or an assurance account, based on the information in a submission, as adjusted under paragraph (a) of this section, and record such deductions and transfers.

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§97.829 [Reserved]

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§97.830 General monitoring, recordkeeping, and reporting requirements.

The owners and operators, and to the extent applicable, the designated representative, of a CSAPR NO_X Ozone Season Group 2 unit, shall comply with the monitoring, recordkeeping, and reporting requirements as provided in this subpart and subpart H of part 75 of this chapter. For purposes of applying such requirements, the definitions in §97.802 and in §72.2 of this chapter shall apply, the terms “affected unit,” “designated representative,” and “continuous emission monitoring system” (or “CEMS”) in part 75 of this chapter shall be deemed to refer to the terms “CSAPR NO_X Ozone Season Group 2 unit,” “designated representative,” and “continuous emission monitoring system” (or “CEMS”) respectively as defined in §97.802, and the term “newly affected unit” shall be deemed to mean “newly affected CSAPR NO_X Ozone Season Group 2 unit”. The owner or operator of a unit that is not a CSAPR NO_X Ozone Season Group 2 unit but that is monitored under §75.72(b)(2)(ii) of this chapter shall comply with the same monitoring, recordkeeping, and reporting requirements as a CSAPR NO_X Ozone Season Group 2 unit.

(a) *Requirements for installation, certification, and data accounting.* The owner or operator of each CSAPR NO_X Ozone Season Group 2 unit shall:

(1) Install all monitoring systems required under this subpart for monitoring NO_X mass emissions and individual unit heat input (including all systems required to monitor NO_X emission rate, NO_X concentration, stack gas moisture content, stack gas flow rate, CO_2 or O_2 concentration, and fuel flow rate, as applicable, in accordance with §§75.71 and 75.72 of this chapter);

(2) Successfully complete all certification tests required under §97.831 and meet all other requirements of this subpart and part 75 of this chapter applicable to the monitoring systems under paragraph (a)(1) of this section; and

(3) Record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section.

(b) *Compliance deadlines.* Except as provided in paragraph (e) of this section, the owner or operator of a CSAPR NO_X Ozone Season Group 2 unit shall meet the monitoring system certification and other requirements of paragraphs (a)(1) and (2) of this section on or before the latest of the following dates and shall record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section on and after the latest of the following dates:

(1) May 1, 2017;

(2) 180 calendar days after the date on which the unit commences commercial operation; or

(3) Where data for the unit are reported on a control period basis under §97.834(d)(1)(ii)(B), and where the compliance date under paragraph (b)(2) of this section is not in a month from May through September, May 1 immediately after the compliance date under paragraph (b)(2) of this section.

(4) The owner or operator of a CSAPR NO_X Ozone Season Group 2 unit for which construction of a new stack or flue or installation of add-on NO_X emission controls is completed after the applicable deadline under paragraph (b)(1), (2), or (3) of this section shall meet the requirements of §75.4(e)(1) through (4) of this chapter, except that:

(i) Such requirements shall apply to the monitoring systems required under §97.830 through §97.835, rather than the monitoring systems required under part 75 of this chapter;

(ii) NO_X emission rate, NO_X concentration, stack gas moisture content, stack gas volumetric flow rate, and O_2 or CO_2 concentration data shall be determined and reported, rather than the data listed in §75.4(e)(2) of this chapter; and

(iii) Any petition for another procedure under §75.4(e)(2) of this chapter shall be submitted under §97.835, rather than §75.66 of this chapter.

(c) *Reporting data.* The owner or operator of a CSAPR NO_X Ozone Season Group 2 unit that does not meet the applicable compliance date set forth in paragraph (b) of this section for any monitoring system under paragraph (a)(1) of this section shall, for each such monitoring system, determine, record, and report maximum potential (or, as appropriate, minimum potential) values for NO_X concentration, NO_X emission rate, stack gas flow rate, stack gas moisture content, fuel flow rate, and any other parameters required to determine NO_X mass emissions and heat input in accordance with §75.31(b)(2) or (c)(3) of this chapter, section 2.4 of appendix D to part 75 of this chapter, or section 2.5 of appendix E to part 75 of this chapter, as applicable.

(d) *Prohibitions.* (1) No owner or operator of a CSAPR NO_X Ozone Season Group 2 unit shall use any alternative monitoring system, alternative reference method, or any other alternative to any requirement of this subpart without having obtained prior written approval in accordance with §97.835.

(2) No owner or operator of a CSAPR NO_X Ozone Season Group 2 unit shall operate the unit so as to discharge, or allow to be discharged, NO_X to the atmosphere without accounting for all such NO_X in accordance with the applicable provisions of this subpart and part 75 of this chapter.

(3) No owner or operator of a CSAPR NO_X Ozone Season Group 2 unit shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method, and thereby avoid monitoring and recording NO_X mass discharged into the atmosphere or heat input, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the applicable provisions of this subpart and part 75 of this chapter.

(4) No owner or operator of a CSAPR NO_X Ozone Season Group 2 unit shall retire or permanently discontinue use of the continuous emission monitoring system, any component thereof, or any other approved monitoring system under this subpart, except under any one of the following circumstances:

(i) During the period that the unit is covered by an exemption under §97.805 that is in effect;

(ii) The owner or operator is monitoring emissions from the unit with another certified monitoring system approved, in accordance with the applicable provisions of this subpart and part 75 of this chapter, by the Administrator for use at that unit that provides emission data for the same pollutant or parameter as the retired or discontinued monitoring system; or

(iii) The designated representative submits notification of the date of certification testing of a replacement monitoring system for the retired or discontinued monitoring system in accordance with §97.831(d)(3)(i).

(e) *Long-term cold storage.* The owner or operator of a CSAPR NO_X Ozone Season Group 2 unit is subject to the applicable provisions of §75.4(d) of this chapter concerning units in long-term cold storage.

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§97.831 Initial monitoring system certification and recertification procedures.

(a) The owner or operator of a CSAPR NO_X Ozone Season Group 2 unit shall be exempt from the initial certification requirements of this section for a monitoring system under §97.830(a)(1) if the following conditions are met:

(1) The monitoring system has been previously certified in accordance with part 75 of this chapter; and

(2) The applicable quality-assurance and quality-control requirements of §75.21 of this chapter and appendices B, D, and E to part 75 of this chapter are fully met for the certified monitoring system described in paragraph (a)(1) of this section.

(b) The recertification provisions of this section shall apply to a monitoring system under §97.830(a)(1) that is exempt from initial certification requirements under paragraph (a) of this section.

(c) If the Administrator has previously approved a petition under §75.17(a) or (b) of this chapter for apportioning the NO_X emission rate measured in a common stack or a petition under §75.66 of this chapter for an alternative to a requirement in

§75.12 or §75.17 of this chapter, the designated representative shall resubmit the petition to the Administrator under §97.835 to determine whether the approval applies under the CSAPR NO_X Ozone Season Group 2 Trading Program.

(d) Except as provided in paragraph (a) of this section, the owner or operator of a CSAPR NO_X Ozone Season Group 2 unit shall comply with the following initial certification and recertification procedures for a continuous monitoring system (*i.e.,* a continuous emission monitoring system and an excepted monitoring system under appendices D and E to part 75 of this chapter) under §97.830(a)(1). The owner or operator of a unit that qualifies to use the low mass emissions excepted monitoring methodology under §75.19 of this chapter or that qualifies to use an alternative monitoring system under subpart E of part 75 of this chapter shall comply with the procedures in paragraph (e) or (f) of this section respectively.

(1) *Requirements for initial certification.* The owner or operator shall ensure that each continuous monitoring system under §97.830(a)(1) (including the automated data acquisition and handling system) successfully completes all of the initial certification testing required under §75.20 of this chapter by the applicable deadline in §97.830(b). In addition, whenever the owner or operator installs a monitoring system to meet the requirements of this subpart in a location where no such monitoring system was previously installed, initial certification in accordance with §75.20 of this chapter is required.

(2) *Requirements for recertification.* Whenever the owner or operator makes a replacement, modification, or change in any certified continuous emission monitoring system under §97.830(a)(1) that may significantly affect the ability of the system to accurately measure or record NO_X mass emissions or heat input rate or to meet the quality-assurance and quality-control requirements of §75.21 of this chapter or appendix B to part 75 of this chapter, the owner or operator shall recertify the monitoring system in accordance with §75.20(b) of this chapter. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit's operation that may significantly change the stack flow or concentration profile, the owner or operator shall recertify each continuous emission monitoring system whose accuracy is potentially affected by the change, in accordance with §75.20(b) of this chapter. Examples of changes to a continuous emission monitoring system that require recertification include replacement of the analyzer, complete replacement of an existing continuous emission monitoring system, or change in location or orientation of the sampling probe or site. Any fuel flowmeter system, and any excepted NO_X monitoring system under appendix E to part 75 of this chapter, under §97.830(a)(1) are subject to the recertification requirements in §75.20(g)(6) of this chapter.

(3) *Approval process for initial certification and recertification.* For initial certification of a continuous monitoring system under §97.830(a)(1), paragraphs (d)(3)(i) through (v) of this section apply. For recertifications of such monitoring systems, paragraphs (d)(3)(i) through (iv) of this section and the procedures in §75.20(b)(5) and (g)(7) of this chapter (in lieu of the procedures in paragraph (d)(3)(v) of this section) apply, provided that in applying paragraphs (d)(3)(i) through (iv) of this section, the words “certification” and “initial certification” are replaced by the word “recertification” and the word “certified” is replaced by with the word “recertified”.

(i) *Notification of certification.* The designated representative shall submit to the appropriate EPA Regional Office and the Administrator written notice of the dates of certification testing, in accordance with §97.833.

(ii) *Certification application.* The designated representative shall submit to the Administrator a certification application for each monitoring system. A complete certification application shall include the information specified in §75.63 of this chapter.

(iii) *Provisional certification date.* The provisional certification date for a monitoring system shall be determined in accordance with §75.20(a)(3) of this chapter. A provisionally certified monitoring system may be used under the CSAPR NO_X Ozone Season Group 2 Trading Program for a period not to exceed 120 days after receipt by the Administrator of the complete certification application for the monitoring system under paragraph (d)(3)(ii) of this section. Data measured and recorded by the provisionally certified monitoring system, in accordance with the requirements of part 75 of this chapter, will be considered valid quality-assured data (retroactive to the date and time of provisional certification), provided that the Administrator does not invalidate the provisional certification by issuing a notice of disapproval within 120 days of the date of receipt of the complete certification application by the Administrator.

(iv) *Certification application approval process.* The Administrator will issue a written notice of approval or disapproval of the certification application to the owner or operator within 120 days of receipt of the complete certification application under paragraph (d)(3)(ii) of this section. In the event the Administrator does not issue such a notice within such 120-day period, each monitoring system that meets the applicable performance requirements of part 75 of this chapter and is included in the certification application will be deemed certified for use under the CSAPR NO_X Ozone Season Group 2 Trading Program.

(A) *Approval notice.* If the certification application is complete and shows that each monitoring system meets the applicable performance requirements of part 75 of this chapter, then the Administrator will issue a written notice of approval of the certification application within 120 days of receipt.

(B) *Incomplete application notice.* If the certification application is not complete, then the Administrator will issue a written notice of incompleteness that sets a reasonable date by which the designated representative must submit the additional information required to complete the certification application. If the designated representative does not comply with the notice of incompleteness by the specified date, then the Administrator may issue a notice of disapproval under paragraph (d)(3)(iv)(C) of this section.

(C) *Disapproval notice.* If the certification application shows that any monitoring system does not meet the performance requirements of part 75 of this chapter or if the certification application is incomplete and the requirement for disapproval under paragraph (d)(3)(iv)(B) of this section is met, then the Administrator will issue a written notice of disapproval of the certification application. Upon issuance of such notice of disapproval, the provisional certification is invalidated by the Administrator and the data measured and recorded by each uncertified monitoring system shall not be considered valid quality-assured data beginning with the date and hour of provisional certification (as defined under §75.20(a)(3) of this chapter).

(D) *Audit decertification.* The Administrator may issue a notice of disapproval of the certification status of a monitor in accordance with §97.832(b).

(v) *Procedures for loss of certification.* If the Administrator issues a notice of disapproval of a certification application under paragraph (d)(3)(iv)(C) of this section or a notice of disapproval of certification status under paragraph (d)(3)(iv)(D) of this section, then:

(A) The owner or operator shall substitute the following values, for each disapproved monitoring system, for each hour of unit operation during the period of invalid data specified under §75.20(a)(4)(iii), §75.20(g)(7), or §75.21(e) of this chapter and continuing until the applicable date and hour specified under §75.20(a)(5)(i) or (g)(7) of this chapter:

(*1*) For a disapproved NO_X emission rate (*i.e.,* NO_X-diluent) system, the maximum potential NO_X emission rate, as defined in §72.2 of this chapter.

(*2*) For a disapproved NO_X pollutant concentration monitor and disapproved flow monitor, respectively, the maximum potential concentration of NO_X and the maximum potential flow rate, as defined in sections 2.1.2.1 and 2.1.4.1 of appendix A to part 75 of this chapter.

(*3*) For a disapproved moisture monitoring system and disapproved diluent gas monitoring system, respectively, the minimum potential moisture percentage and either the maximum potential CO_2 concentration or the minimum potential O_2 concentration (as applicable), as defined in sections 2.1.5, 2.1.3.1, and 2.1.3.2 of appendix A to part 75 of this chapter.

(*4*) For a disapproved fuel flowmeter system, the maximum potential fuel flow rate, as defined in section 2.4.2.1 of appendix D to part 75 of this chapter.

(*5*) For a disapproved excepted NO_X monitoring system under appendix E to part 75 of this chapter, the fuel-specific maximum potential NO_X emission rate, as defined in §72.2 of this chapter.

(B) The designated representative shall submit a notification of certification retest dates and a new certification application in accordance with paragraphs (d)(3)(i) and (ii) of this section.

(C) The owner or operator shall repeat all certification tests or other requirements that were failed by the monitoring system, as indicated in the Administrator's notice of disapproval, no later than 30 unit operating days after the date of issuance of the notice of disapproval.

(e) The owner or operator of a unit qualified to use the low mass emissions (LME) excepted methodology under §75.19 of this chapter shall meet the applicable certification and recertification requirements in §§75.19(a)(2) and 75.20(h) of this chapter. If the owner or operator of such a unit elects to certify a fuel flowmeter system for heat input determination, the owner or operator shall also meet the certification and recertification requirements in §75.20(g) of this chapter.

(f) The designated representative of each unit for which the owner or operator intends to use an alternative monitoring system approved by the Administrator under subpart E of part 75 of this chapter shall comply with the applicable notification and application procedures of §75.20(f) of this chapter.

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§97.832 Monitoring system out-of-control periods.

(a) *General provisions.* Whenever any monitoring system fails to meet the quality-assurance and quality-control requirements or data validation requirements of part 75 of this chapter, data shall be substituted using the applicable missing data procedures in subpart D or subpart H of, or appendix D or appendix E to, part 75 of this chapter.

(b) *Audit decertification.* Whenever both an audit of a monitoring system and a review of the initial certification or recertification application reveal that any monitoring system should not have been certified or recertified because it did not meet a particular performance specification or other requirement under §97.831 or the applicable provisions of part 75 of this chapter, both at the time of the initial certification or recertification application submission and at the time of the audit, the Administrator will issue a notice of disapproval of the certification status of such monitoring system. For the purposes of this paragraph, an audit shall be either a field audit or an audit of any information submitted to the Administrator or any State or permitting authority. By issuing the notice of disapproval, the Administrator revokes prospectively the certification status of the monitoring system. The data measured and recorded by the monitoring system shall not be considered valid quality-assured data from the date of issuance of the notification of the revoked certification status until the date and time that the owner or operator completes subsequently approved initial certification or recertification tests for the monitoring system. The owner or operator shall follow the applicable initial certification or recertification procedures in §97.831 for each disapproved monitoring system.

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§97.833 Notifications concerning monitoring.

The designated representative of a CSAPR NO_X Ozone Season Group 2 unit shall submit written notice to the Administrator in accordance with §75.61 of this chapter.

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§97.834 Recordkeeping and reporting.

(a) *General provisions.* The designated representative shall comply with all recordkeeping and reporting requirements in paragraphs (b) through (e) of this section, the applicable recordkeeping and reporting requirements under §75.73 of this chapter, and the requirements of §97.814(a).

(b) *Monitoring plans.* The owner or operator of a CSAPR NO_X Ozone Season Group 2 unit shall comply with the requirements of §75.73(c) and (e) of this chapter.

(c) *Certification applications.* The designated representative shall submit an application to the Administrator within 45 days after completing all initial certification or recertification tests required under §97.831, including the information required under §75.63 of this chapter.

(d) *Quarterly reports.* The designated representative shall submit quarterly reports, as follows:

(1)(i) If a CSAPR NO_X Ozone Season Group 2 unit is subject to the Acid Rain Program or the CSAPR NO_X Annual Trading Program or if the owner or operator of such unit chooses to report on an annual basis under this subpart, then the designated representative shall meet the requirements of subpart H of part 75 of this chapter (concerning monitoring of NO_X mass emissions) for such unit for the entire year and report the NO_X mass emissions data and heat input data for such unit for the entire year.

(ii) If a CSAPR NO_X Ozone Season Group 2 unit is not subject to the Acid Rain Program or the CSAPR NO_X Annual Trading Program, then the designated representative shall either:

(A) Meet the requirements of subpart H of part 75 of this chapter for such unit for the entire year and report the NO_X mass emissions data and heat input data for such unit for the entire year in accordance with paragraph (d)(1)(i) of this section; or

(B) Meet the requirements of subpart H of part 75 of this chapter (including the requirements in §75.74(c) of this chapter) for such unit for the control period and report the NO_X mass emissions data and heat input data (including the data described in §75.74(c)(6) of this chapter) for such unit only for the control period of each year.

(2) The designated representative shall report the NO_X mass emissions data and heat input data for a CSAPR NO_X Ozone Season Group 2 unit, in an electronic quarterly report in a format prescribed by the Administrator, for each calendar quarter indicated under paragraph (d)(1) of this section beginning by the latest of:

(i) The calendar quarter covering May 1, 2017 through June 30, 2017;

(ii) The calendar quarter corresponding to the earlier of the date of provisional certification or the applicable deadline for initial certification under §97.830(b); or

(iii) For a unit that reports on a control period basis under paragraph (d)(1)(ii)(B) of this section, if the calendar quarter under paragraph (d)(2)(ii) of this section does not include a month from May through September, the calendar quarter covering May 1 through June 30 immediately after the calendar quarter under paragraph (d)(2)(ii) of this section.

(3) The designated representative shall submit each quarterly report to the Administrator within 30 days after the end of the calendar quarter covered by the report. Quarterly reports shall be submitted in the manner specified in §75.73(f) of this chapter.

(4) For CSAPR NO_X Ozone Season Group 2 units that are also subject to the Acid Rain Program, CSAPR NO_X Annual Trading Program, CSAPR SO_2 Group 1 Trading Program, or CSAPR SO_2 Group 2 Trading Program, quarterly reports shall include the applicable data and information required by subparts F through H of part 75 of this chapter as applicable, in addition to the NO_X mass emission data, heat input data, and other information required by this subpart.

(5) The Administrator may review and conduct independent audits of any quarterly report in order to determine whether the quarterly report meets the requirements of this subpart and part 75 of this chapter, including the requirement to use substitute data.

(i) The Administrator will notify the designated representative of any determination that the quarterly report fails to meet any such requirements and specify in such notification any corrections that the Administrator believes are necessary to make through resubmission of the quarterly report and a reasonable time period within which the designated representative must respond. Upon request by the designated representative, the Administrator may specify reasonable extensions of such time period. Within the time period (including any such extensions) specified by the Administrator, the designated representative shall resubmit the quarterly report with the corrections specified by the Administrator, except to the extent the designated representative provides information demonstrating that a specified correction is not necessary because the quarterly report already meets the requirements of this subpart and part 75 of this chapter that are relevant to the specified correction.

(ii) Any resubmission of a quarterly report shall meet the requirements applicable to the submission of a quarterly report under this subpart and part 75 of this chapter, except for the deadline set forth in paragraph (d)(3) of this section.

(e) *Compliance certification.* The designated representative shall submit to the Administrator a compliance certification (in a format prescribed by the Administrator) in support of each quarterly report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit's emissions are correctly and fully monitored. The certification shall state that:

(1) The monitoring data submitted were recorded in accordance with the applicable requirements of this subpart and part 75 of this chapter, including the quality assurance procedures and specifications;

(2) For a unit with add-on NO_X emission controls and for all hours where NO_X data are substituted in accordance with §75.34(a)(1) of this chapter, the add-on emission controls were operating within the range of parameters listed in the quality assurance/quality control program under appendix B to part 75 of this chapter and the substitute data values do not systematically underestimate NO_X emissions; and

(3) For a unit that is reporting on a control period basis under paragraph (d)(1)(ii)(B) of this section, the NO_X emission rate and NO_X concentration values substituted for missing data under subpart D of part 75 of this chapter are calculated using only values from a control period and do not systematically underestimate NO_X emissions.

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§97.835 Petitions for alternatives to monitoring, recordkeeping, or reporting requirements.

(a) The designated representative of a CSAPR NO_X Ozone Season Group 2 unit may submit a petition under §75.66 of this chapter to the Administrator, requesting approval to apply an alternative to any requirement of §§97.830 through 97.834.

(b) A petition submitted under paragraph (a) of this section shall include sufficient information for the evaluation of the petition, including, at a minimum, the following information:

(1) Identification of each unit and source covered by the petition;

(2) A detailed explanation of why the proposed alternative is being suggested in lieu of the requirement;

(3) A description and diagram of any equipment and procedures used in the proposed alternative;

(4) A demonstration that the proposed alternative is consistent with the purposes of the requirement for which the alternative is proposed and with the purposes of this subpart and part 75 of this chapter and that any adverse effect of approving the alternative will be *de minimis;* and

(5) Any other relevant information that the Administrator may require.

(c) Use of an alternative to any requirement referenced in paragraph (a) of this section is in accordance with this subpart only to the extent that the petition is approved in writing by the Administrator and that such use is in accordance with such approval.

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Need assistance?

Consideration supporting this determination is available in the docket where indicated under **ADDRESSES**.

G. Protest Activities

The Coast Guard respects the First Amendment rights of protesters. Protesters are asked to contact the person listed in the **FOR FURTHER INFORMATION CONTACT** section to coordinate protest activities so that your message can be received without jeopardizing the safety or security of people, places or vessels.

List of Subjects in 33 CFR Part 165

Harbors, Marine safety, Navigation (water), Reporting and recordkeeping requirements, Security measures, Waterways.

For the reasons discussed in the preamble, the Coast Guard amends 33 CFR part 165 as follows:

PART 165—REGULATED NAVIGATION AREAS AND LIMITED ACCESS AREAS

■ 1. The authority citation for part 165 continues to read as follows:

Authority: 33 U.S.C. 1231; 50 U.S.C. 191; 33 CFR 1.05–1, 6.04–1, 6.04–6, and 160.5; Department of Homeland Security Delegation No. 0170.1.

■ 2. Add § 165.T05–1065 to read as follows:

§ 165.T05–1065 Safety Zone; Oregon Inlet, Dare County, NC.

(a) *Location.* The following area is a safety zone: all navigable waters of Oregon Inlet, within 100 yards of active demolition work and demolition equipment, along the old Herbert C. Bonner Bridge, which follows a line beginning at approximate position 35°46′47″ N, 75°32′41″ W, then southeast to 35°46′37″ N, 75°32′33″ W, then southeast to 35°46′09″ N, 75°31′59″ W, then southeast to 35°46′03″ N, 75°31′51″ W, then southeast to 35°46′01″ N, 75°31′40″ W (NAD 1983) in Dare County, NC.

(b) *Definitions.* As used in this section—

Designated representative means a Coast Guard Patrol Commander, including a Coast Guard commissioned, warrant, or petty officer designated by the Captain of the Port North Carolina (COTP) for the enforcement of the safety zone.

Captain of the Port means the Commander, Sector North Carolina.

Demolition crews means persons and vessels involved in support of demolition.

(c) *Regulations.* (1) The general regulations governing safety zones in § 165.23 apply to the area described in paragraph (a) of this section.

(2) With the exception of demolition crews, entry into or remaining in this safety zone is prohibited.

(3) All vessels within this safety zone when this section becomes effective must depart the zone immediately.

(4) The Captain of the Port, North Carolina can be reached through the Coast Guard Sector North Carolina Command Duty Officer, Wilmington, North Carolina at telephone number 910–343–3882.

(5) The Coast Guard and designated security vessels enforcing the safety zone can be contacted on VHF–FM marine band radio channel 13 (165.65 MHz) and channel 16 (156.8 MHz).

(d) *Enforcement.* The U.S. Coast Guard may be assisted in the patrol and enforcement of the safety zone by Federal, State, and local agencies.

(e) *Enforcement period.* This regulation will be enforced from March 4, 2019, through March 30, 2020.

(f) *Public notification.* The Coast Guard will notify the public of the active enforcement times at least 48 hours in advance by transmitting Broadcast Notice to Mariners via VHF–FM marine channel 16.

Dated: March 4, 2019.

Bion B. Stewart,

Captain, U. S. Coast Guard Captain of the Port North Carolina.

[FR Doc. 2019–04219 Filed 3–7–19; 8:45 am]

BILLING CODE 9110–04–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 51 and 52

[EPA–HQ–OAR–2018–0595; FRL–9990–33–OAR]

RIN 2060–AU08

Emissions Monitoring Provisions in State Implementation Plans Required Under the NO_X SIP Call

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The Environmental Protection Agency (EPA) is revising some of the regulations that were originally promulgated in 1998 to implement the NO_X SIP Call. The revisions give covered states greater flexibility concerning the form of the nitrogen oxides (NO_X) emissions monitoring requirements that the states must include in their state implementation plans (SIPs) for certain emissions sources. Other revisions remove obsolete provisions and clarify the remaining regulations but do not substantively alter any current regulatory requirements.

DATES: This rule is effective as of March 8, 2019.

ADDRESSES: EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2018–0595. All documents in the docket are listed on the *http://www.regulations.gov* website. Although listed in the index, some information is not publicly available, *e.g.,* confidential business information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and will be publicly available only in hard copy form. Publicly available docket materials are available electronically through *http://www.regulations.gov.*

FOR FURTHER INFORMATION CONTACT: David Lifland, Clean Air Markets Division, Office of Atmospheric Programs, U.S. Environmental Protection Agency, MC 6204M, 1200 Pennsylvania Avenue NW, Washington, DC 20460; 202–343–9151; *lifland.david@epa.gov.*

SUPPLEMENTARY INFORMATION:

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I. Overview of the Action

This section provides an overview of the action, including a summary of the amendments and their estimated impacts as well as information concerning potentially affected entities and statutory authority.

Section II provides a summary of the proposal for this action, including background information. In section III, EPA summarizes and responds to comments received on the proposal. EPA's final action is set forth in section IV, and section V discusses the estimated impacts of the amendments. Section VI addresses reviews required under various statutes and executive orders as well as determinations concerning applicable rulemaking and judicial review provisions.

A. Summary of Amendments and Estimated Impacts

On September 27, 2018, EPA published in the **Federal Register** a proposal [1] to amend the existing NO_X SIP Call regulations [2] to allow states to amend their SIPs, for NO_X SIP Call purposes only, to establish emissions monitoring requirements for certain units other than requirements to monitor according to 40 CFR part 75. This action finalizes the amendment generally as proposed, with minor further revisions discussed in section IV of this document. Ultimately, such alternate monitoring requirements could be made available to sources through states' revisions to their SIPs, with consequent potential reductions in some units' monitoring costs. The group of units affected under the SIPs adopted to meet the NO_X SIP Call comprises both existing and new electricity generating units (EGUs) as well as certain other existing and new industrial units (non-EGUs). Within this overall group, the set of existing units potentially affected by the amendment includes approximately 285 non-EGU boilers and combustion turbines and approximately 30 EGUs—specifically, combustion turbines that are considered large EGUs for NO_X SIP Call purposes and that are not required to monitor according to part 75 under other programs such as the Acid Rain Program or a Cross-State Air Pollution Rule (CSAPR) trading program. States, not EPA, will decide whether to revise the monitoring requirements in their SIPs as allowed under this amendment, and EPA lacks complete information on the remaining monitoring requirements that the sources would face if a state decides to make such revisions, leaving considerable uncertainty regarding the amount of monitoring cost reductions that may occur. However, using information from comments and assumptions concerning the sources' remaining monitoring requirements, EPA estimates annual monitoring cost reductions from this action in the range of $1.2 million to $3.3 million. Because this action is not expected to cause any change in emissions or air quality, the monitoring cost reductions will constitute net benefits from the action.

In addition, EPA is eliminating several obsolete provisions of the NO_X SIP Call regulations that no longer have any substantive effect on the regulatory requirements faced by states or sources and is making clarifying amendments—all of which EPA considers non-substantive—to the remaining regulations. The additional amendments also include updates to several cross-references in the CSAPR regulations that refer to an obsolete provision of the NO_X SIP Call regulations. The specific additional amendments discussed in the proposal are identified in section II.C. of this document, and the amendments are being finalized generally as proposed, with minor further revisions discussed in section IV of this document.

B. Potentially Affected Entities

This action does not apply directly to any emissions sources but instead amends existing regulatory requirements applicable to the SIPs of Alabama, Connecticut, Delaware, Illinois, Indiana, Kentucky, Maryland, Massachusetts, Michigan, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Rhode Island, South Carolina, Tennessee, Virginia, West Virginia, and the District of Columbia. If an affected jurisdiction chooses to revise its SIP in response to these amendments, sources in the jurisdiction could be indirectly affected if they are subject to emissions monitoring requirements for purposes of the NO_X SIP Call and are not independently subject to comparable requirements under another program such as the Acid Rain Program or a CSAPR trading program. Generally, the types of sources that could be indirectly affected are fossil fuel-fired boilers and stationary combustion turbines with heat input capacities over 250 million British thermal units per hour (mmBtu/hr) or serving electricity generators with capacities over 25 megawatts (MW). Sources meeting these criteria operate in a variety of industries, including but not limited to the following:

NAICS* code	Examples of industries with potentially affected sources
221112	Fossil fuel-fired electric power generation.
3112	Grain and oilseed milling.
3221	Pulp, paper, and paperboard mills.
3241	Petroleum and coal products manufacturing.
3251	Basic chemical manufacturing.
3311	Iron and steel mills and ferroalloy manufacturing.
6113	Colleges, universities, and professional schools.

* North American Industry Classification System.

C. Statutory Authority

Statutory authority for this action is provided by Clean Air Act (CAA) sections 110 and 301, 42 U.S.C. 7410 and 7601, which also provided statutory authority for issuance of the existing NO_X SIP Call regulations that EPA is amending in this action.[3]

II. Summary of the Proposal

This section summarizes the proposal for this action. Section II.A. repeats some of the background information from the proposal. Section II.B. addresses the proposed amendment to the NO_X SIP Call's emissions monitoring requirements, reiterating the proposed rationale and summarizing the proposal's discussion of projected impacts. Sections II.C. and II.D. summarize the remaining proposed amendments and describe the public comment process.

A. Background

Under the CAA, EPA establishes and periodically revises national ambient air quality standards (NAAQS) for certain pollutants, including ground-level ozone, while states have primary responsibility for attaining the NAAQS through the adoption of emission control measures in their SIPs. Under CAA section 110(a)(2)(D)(i)(I), 42 U.S.C. 7410(a)(2)(D)(i)(I), often called the ''good neighbor'' provision, each state is

[1] Emissions Monitoring Provisions in State Implementation Plans Required Under the NO_X SIP Call, Proposed Rule, 83 FR 48751 (Sept. 27, 2018).

[2] Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone (NO_X SIP Call), 63 FR 57356 (Oct. 27, 1998) (codified in relevant part at 40 CFR 51.121 and 51.122). Amendments to the NO_X SIP Call regulations made between issuance and implementation are described in the proposal for this action, 83 FR at 48755 & nn.11–15.

[3] *See, e.g.,* 63 FR at 57366, 57479.

required to include provisions in its SIP prohibiting emissions that ''will . . . contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to any [NAAQS].'' In 1998, EPA issued the NO_X SIP Call (the Rule) identifying good neighbor obligations with respect to the 1979 1-hour ozone NAAQS and calling for SIP revisions to address those obligations.[4] The Rule's regulatory text was codified at 40 CFR 51.121, addressing the required SIP revisions, and 40 CFR 51.122, addressing states' periodic reporting requirements. As implemented, the Rule required 20 states and the District of Columbia [5] to revise their SIPs to reduce their sources' emissions of NO_X, an ozone precursor, during the May–September ''ozone season'' starting in 2004.

To implement the NO_X SIP Call's emissions reduction requirements, EPA promulgated a ''budget'' for the statewide seasonal NO_X emissions from each covered state. Each state's emissions budget was calculated as the state's projected 2007 pre-control or ''baseline'' emissions inventory minus the state's required emissions reduction. The Rule did not mandate that states follow any particular approach for achieving their required emissions reductions. Instead, states retained wide discretion regarding which sources in their states to control and what control measures to employ. Each state was simply required to demonstrate that whatever control measures it chose to include in its SIP revision would be sufficient to ensure that projected 2007 statewide seasonal NO_X emissions from its sources would not exceed its emissions budget.

Besides the general flexibility given to states regarding the choices of sources and control measures, the NO_X SIP Call included additional provisions designed to increase compliance flexibility. Most notably, the Rule allowed states to adopt interstate emission allowance trading programs as control measures to accomplish some or all of the required emissions reductions. EPA also provided a model rule for an EPA-administered interstate trading program—the NO_X Budget Trading Program (NBTP)—that would meet all the Rule's SIP approval criteria for a trading program for two types of sources: Fossil fuel-fired EGU boilers and combustion turbines serving electricity generators with capacity ratings greater than 25 MW (large EGUs), and fossil fuel-fired non-EGU boilers and combustion turbines with heat input ratings greater than 250 mmBtu/hr (large non-EGU boilers and turbines).

While generally oriented toward providing states and sources with compliance flexibility, the NO_X SIP Call also included two conditional provisions that would become mandatory SIP requirements for large EGUs and large non-EGU boilers and turbines if states chose to include any emission control measures for these types of sources in their SIP revisions. First, under § 51.121(f)(2), any control measures imposed on these types of sources would be required to include enforceable limits on the sources' seasonal NO_X mass emissions. These limits could take several forms, including either limits on individual sources or collective limits on the group of all such sources in a state. Second, under § 51.121(i)(4), these sources would be required to monitor and report their seasonal NO_X mass emissions according to the provisions of 40 CFR part 75.[6] One way a state could meet these two SIP requirements was to adopt the NBTP, because the NBTP included provisions addressing both requirements and was expressly designed as a potential control measure for these types of sources.

All the jurisdictions subject to the NO_X SIP Call as implemented ultimately chose to adopt the NBTP for large EGUs and large non-EGU boilers and turbines as part of their required SIP revisions. By adopting control measures applicable to large EGUs and large non-EGU boilers and turbines into their SIPs, all the affected jurisdictions triggered the obligations for their SIPs to include enforceable mass emissions limits and part 75 monitoring requirements for these types of sources. These requirements have remained in effect despite the discontinuation of the NBTP following the 2008 ozone season.[7]

The NBTP was implemented starting in 2003 for sources in several northeastern states and in 2004 for sources in most of the remaining NO_X SIP Call states. Missouri sources joined the NBTP in 2007, and EPA continued to administer the NBTP through the 2008 ozone season. Since the 2008 ozone season, EPA has replaced the NBTP with a series of three similar interstate emission allowance trading programs designed to address eastern states' good neighbor obligations with respect to ozone NAAQS more recent than the 1979 1-hour ozone NAAQS. The NBTP's three successor seasonal NO_X trading programs were established under the Clean Air Interstate Rule (CAIR),[8] which was remanded to EPA for replacement; [9] the original CSAPR,[10] which replaced CAIR; and most recently the CSAPR Update.[11] The seasonal NO_X trading programs established under CAIR and the original CSAPR were both designed to address the 1997 8-hour ozone NAAQS, while the trading program established under the CSAPR Update was designed to address the 2008 8-hour ozone NAAQS. The CAIR seasonal NO_X trading program operated from 2009 through 2014, the original CSAPR seasonal NO_X trading program started operating in 2015,[12] and the CSAPR Update trading program started operating in 2017.

For purposes of this action, the most important difference between the NBTP and its successor seasonal NO_X trading programs concerns the types of sources participating in the various programs. As discussed above, the NBTP was designed to cover both large EGUs and large non-EGU boilers and turbines. In contrast, by default the three successor trading programs have covered only units considered EGUs under those

[4] 63 FR 57356. As described in the proposal for this action, an amendment to the NO_X SIP Call made before the Rule's implementation indefinitely stayed the additional findings of good neighbor obligations with respect to the 1997 8-hour ozone NAAQS that were included in the Rule as issued. *See* 83 FR at 48755.

[5] The Rule as implemented applies to Connecticut, Delaware, Illinois, Indiana, Kentucky, Maryland, Massachusetts, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Rhode Island, South Carolina, Tennessee, Virginia, and West Virginia; portions of Alabama, Michigan, and Missouri; and the District of Columbia. For simplicity, this document often refers to all the jurisdictions with obligations under the CAA and the NO_X SIP Call, including the District of Columbia, as ''states.''

[6] For brevity, this document generally refers to the monitoring, recordkeeping, and reporting requirements in 40 CFR part 75 as ''part 75 monitoring requirements.''

[7] Some states expanded NBTP applicability under their SIPs to include additional sources such as process heaters, cement kilns, and smaller EGUs. Unlike large EGUs and large non-EGU boilers and turbines, the additional sources are not subject to the NO_X SIP Call's ongoing obligation under § 51.121(i)(4) for SIPs to include part 75 monitoring requirements and therefore are not affected by the amendments being finalized in this action.

[8] 70 FR 25162 (May 12, 2005) (SIP requirements); 71 FR 25328 (Apr. 28, 2006) (parallel Federal implementation plan requirements).

[9] *North Carolina* v. *EPA,* 531 F.3d 896 (D.C. Cir. 2008), *modified on rehearing,* 550 F.3d 1176 (D.C. Cir. 2008).

[10] 76 FR 48208 (Aug. 8, 2011); *see also* 76 FR 80760 (Dec. 27, 2011) (adding seasonal NO_X emissions reduction requirements for sources in five states), 79 FR 71663 (Dec. 3, 2014) (tolling implementation dates by three years).

[11] 81 FR 74504 (Oct. 26, 2016). Consolidated challenges to the CSAPR Update are pending in *Wisconsin* v. *EPA,* No. 16–1406 (D.C. Cir. argued Oct. 3, 2018).

[12] The original CSAPR seasonal NO_X trading program remains in effect for sources in Georgia but after 2016 has not applied to sources in any state subject to the NO_X SIP Call as implemented.

programs, which generally means all units that would be classified as NO_X SIP Call large EGUs as well as a small subset of the units that would be classified as NO_X SIP Call large non-EGU boilers and turbines.[13] Under the CAIR seasonal NO_X trading program, most NO_X SIP Call states exercised an option to expand program applicability to include all their NO_X SIP Call large non-EGU boilers and turbines, but the option was eliminated under the original CSAPR seasonal NO_X trading program and no state has exercised the restored option made available under the CSAPR Update trading program. Consequently, at present most NO_X SIP Call large non-EGU boilers and turbines do not participate in a successor trading program to the NBTP.

The second relevant difference between the NBTP and its successor trading programs concerns the various programs' geographic areas of coverage. At present, EGUs in fourteen NO_X SIP Call states participate in the CSAPR Update trading program.[14] EGUs in the remaining seven NO_X SIP Call jurisdictions do not currently participate in a successor trading program to the NBTP, although most such units are subject to other EPA programs with comparable part 75 monitoring requirements.[15]

In the CAIR rulemaking, EPA amended the NO_X SIP Call regulations both to provide that the NBTP would be discontinued upon implementation of the CAIR seasonal NO_X trading program and to require states to adopt replacement control measures into their SIPs to ensure continued achievement of the portions of their NO_X SIP Call emissions reduction requirements that had been met through the NBTP.[16] As noted above, notwithstanding the discontinuation of the NBTP, the NO_X SIP Call's requirements for enforceable mass emissions limits and part 75 monitoring have continued to apply to large EGUs and large non-EGU boilers and turbines in all affected states. Since the CAIR rulemaking, EPA has worked with NO_X SIP Call states individually to assist them in revising their SIPs to meet these ongoing NO_X SIP Call requirements, whether through use of the NBTP's successor trading programs (to the extent those options have been available) or through other replacement control measures.

Under CAA section 107(d)(3)(E), 42 U.S.C. 7407(d)(3)(E), redesignation of an area to attainment of a NAAQS requires a determination that the improvement in air quality is due to ''permanent and enforceable'' emissions reductions. At least 140 EPA final actions redesignating areas in 20 states to attainment with an ozone NAAQS or a fine particulate matter ($PM_{2.5}$) NAAQS—because NO_X is a precursor to $PM_{2.5}$ as well as ozone—have relied in part on the NO_X SIP Call's emissions reductions.[17] In this action, to avoid any possible argument that amendments to the NO_X SIP Call might result in a lessening of permanence and enforceability that could threaten continued reliance on the Rule's emissions reductions to support other actions, EPA is not substantively amending the Rule's key provisions supporting these attributes. These key provisions include the statewide emissions budgets and general enforceability and monitoring requirements as well as the requirements for enforceable limits on seasonal NO_X mass emissions from large EGUs and large non-EGU boilers and turbines.[18] As discussed in section II.B. of this document, EPA believes that under current circumstances, the amendment to allow states to establish alternate monitoring requirements for large EGUs and large non-EGU boilers and turbines does not undermine assurance that the Rule's required emissions reductions will continue to be achieved and therefore does not pose a risk to the permanence and enforceability of the emissions reductions.

B. Proposed Amendment to Emissions Monitoring Requirements

The only substantive amendment to the NO_X SIP Call regulations proposed for this action concerns emissions monitoring requirements. Under 40 CFR 51.121(i)(4) of the regulations as originally promulgated, where a state's SIP revision contains control measures for large EGUs or large non-EGU boilers and turbines, the SIP must also require part 75 monitoring for these types of sources. As discussed in section II.A. of this document, all NO_X SIP Call states triggered this requirement by including control measures in their SIPs for these types of sources, and the requirement has remained in effect despite the discontinuation of the NBTP after the 2008 ozone season. For this action, EPA proposed to amend the provision at § 51.121(i)(4) to make the inclusion of part 75 monitoring requirements for these sources in SIPs optional rather than mandatory for NO_X SIP Call purposes.[19] The SIPs would still need to include some form of emissions monitoring requirements for these types of sources, consistent with the Rule's general enforceability and monitoring requirements at § 51.121(f)(1) and (i)(1), respectively, but states would no longer be required to satisfy these general Rule requirements specifically through the adoption of part 75 monitoring requirements. EPA noted that finalization of this proposed amendment would not in itself eliminate part 75 monitoring requirements for any sources but would enable EPA to approve SIP submittals replacing these requirements for NO_X SIP Call purposes with other forms of monitoring requirements.

In the proposal, EPA discussed the following rationale for the proposed amendment to emissions monitoring requirements.[20] The condition that SIPs must include part 75 monitoring requirements was established based on

[13] For example, under the NO_X SIP Call as implemented, a unit qualifying as exempt from the Acid Rain Program under the provision for cogeneration units at 40 CFR 72.6(b)(4) would be classified as a non-EGU, but in some instances such a unit could be covered under the CAIR, original CSAPR, and CSAPR Update trading programs as an EGU.

[14] The CSAPR Update applies to EGUs in the NO_X SIP Call states of Alabama, Illinois, Indiana, Kentucky, Maryland, Michigan, Missouri, New Jersey, New York, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia as well as eight additional states that are not subject to the NO_X SIP Call as implemented.

[15] EGUs in the NO_X SIP Call jurisdictions of Connecticut, Delaware, Massachusetts, North Carolina, Rhode Island, South Carolina, and the District of Columbia are not subject to the CSAPR Update. All NO_X SIP Call EGUs in North Carolina and South Carolina are required to monitor NO_X mass emissions according to part 75 under a CSAPR trading program for annual NO_X emissions, and most NO_X SIP Call EGUs in the remaining jurisdictions are required to monitor NO_X emission rate and heat input rate according to part 75 under the Acid Rain Program.

[16] 40 CFR 51.121(r); *see also* 40 CFR 51.123(bb) and 52.38(b)(10)(ii) (authorizing use of CAIR and CSAPR Update seasonal NO_X trading programs as NBTP replacement control measures for large non-EGU boilers and turbines).

[17] *See* Redesignation Actions Relying on NO_X SIP Call Emissions Reductions (August 2018), available in the docket for this action. EPA notes that reliance on the Rule's emissions reductions as permanent and enforceable for purposes of redesignation actions has been upheld by multiple courts of appeals. *Sierra Club* v. *EPA,* 774 F.3d 383, 397–99 (7th Cir. 2014); *Sierra Club* v. *EPA,* 793 F.3d 656, 665–68 (6th Cir. 2015).

[18] EPA notes that the implementation rules for both the 1997 ozone NAAQS and the 2008 ozone NAAQS have required that the NO_X SIP Call in general and states' emissions budgets in particular will continue to apply after revocation of the previous NAAQS and have also made clear that any modifications to control requirements approved into a SIP pursuant to the Rule are subject to anti-backsliding requirements under CAA section 110(l), 42 U.S.C. 7410(l). *See* 40 CFR 51.905(f), 51.1105(e).

[19] The amendment would apply only for NO_X SIP Call purposes and would not authorize states to create exceptions to any part 75 monitoring requirements that might apply to a source under a different legal authority.

[20] 83 FR at 48757–58.

determinations that, first, a requirement for mass emissions limits for large EGUs and large non-EGU boilers and turbines was feasible and provided the greatest assurance that the NO_X SIP Call's required emissions reductions would be achieved, and second, part 75 monitoring was a feasible and cost-effective way to ensure compliance with the mass emissions limits for these sources.[21] (Part 75 monitoring requirements were also established independently as an essential element of the now-discontinued NBTP, which like EPA's other emission allowance trading programs could function only with timely reporting of consistent, quality-assured mass emissions data by all participating units.) To ensure that the NO_X SIP Call's emissions reductions can continue to be relied on as permanent and enforceable for purposes of other actions, EPA did not propose to amend the Rule's existing requirements regarding enforceable mass emissions limits for these sources. However, EPA proposed the view that under current circumstances, allowing states to establish alternate monitoring requirements for large EGUs and large non-EGU boilers and turbines would not pose a risk to the permanence and enforceability of the Rule's emissions reductions.

The first relevant current circumstance EPA discussed was the substantial margins by which all NO_X SIP Call states are now complying with the portions of their statewide emissions budgets assigned to large EGUs and large non-EGU boilers and turbines. As shown in Table 1 of the proposal, which is reproduced without change as Table 1 of this document, in 2017, seasonal NO_X emissions from sources that would have been subject to the NBTP across the region covered by the NO_X SIP Call were approximately 200,000 tons, which is less than 40% of the sum of the relevant portions of the statewide final NO_X budgets. Table 1 also shows that no state's reported emissions exceeded 71% of the relevant portion of its budget.[22] As noted by EPA, these comparisons demonstrate that the Rule's required emissions reductions would continue to be achieved even with substantial increases in emissions from current levels. EPA also observed that the possibility of such large increases in emissions is remote because of requirements under other state and Federal environmental programs[23] and changes to the fleet of affected sources since 2008.[24]

TABLE 1—2017 EMISSIONS AND RELEVANT EMISSIONS BUDGET AMOUNTS BY STATE

State	NO_X emissions during the 2017 ozone season (tons) from:				Portion of statewide emissions budget assigned to NBTP sources (tons)
	NBTP sources also subject to part 75 under other programs	Other NBTP large EGUs and large non-EGU boilers and turbines	Other NBTP sources subject to part 75 under NSC SIPs	Total for all NBTP sources	
Alabama (part)	7,166	1,911	0	9,077	25,497
Connecticut	380	10	39	430	4,477
Delaware	324	511	0	835	5,227
District of Columbia	0	20	0	20	233
Illinois	13,038	1,493	0	14,531	35,557
Indiana	20,396	1,201	823	22,419	55,729
Kentucky	19,978	75	0	20,053	36,109
Maryland	2,422	516	0	2,939	15,466
Massachusetts	734	113	32	879	12,861
Michigan (part)	14,580	205	0	14,785	31,247
Missouri (part)	9,486	0	0	9,486	13,459
New Jersey	1,646	310	0	1,956	13,022
New York	4,062	941	611	5,614	41,385
North Carolina	16,352	1,689	0	18,041	34,703
Ohio	20,012	993	0	21,005	49,842
Pennsylvania	13,616	837	0	14,453	50,843
Rhode Island	193	0	0	193	936
South Carolina	5,030	1,043	0	6,074	19,678
Tennessee	7,785	2,350	0	10,135	31,480
Virginia	7,462	589	0	8,051	21,195
West Virginia	18,187	276	0	18,463	29,507
Total	182,849	15,084	1,505	199,438	528,453

Data sources: Emissions data are from EPA's Air Markets Program Database, *https://ampd.epa.gov/ampd*. In a few cases where 2017 data are not available, the most recent available data are used instead. Budget data are from The NO_X Budget Trading Program: 2008 Emission, Compliance, and Market Analyses (July 2009) at 14, available in the docket for this action.

The second relevant current circumstance EPA discussed was that even with the proposed amendment, part 75 monitoring requirements would remain in effect for most NO_X SIP Call large EGUs pursuant to other regulatory requirements, including the Acid Rain Program and the CSAPR trading programs, and these large EGUs are responsible for most of the collective emissions of NO_X SIP Call large EGUs and large non-EGU boilers and turbines.

[21] *See* 63 FR at 57451–52.

[22] Reported 2017 emissions from Missouri sources were just over 70% of the relevant portion of the state's budget.

[23] For example, for the 11 states covered in their entirety under both programs—Illinois, Indiana, Kentucky, Maryland, New Jersey, New York, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia—EGU emissions budgets under the current CSAPR Update seasonal NO_X trading program range from 17% to 66% of the portions of the respective states' NO_X SIP Call statewide budgets based on EGU emissions. *Compare* 40 CFR 97.810(a) (CSAPR Update budgets) *with* 65 FR 11222, 11225 (Mar. 2, 2000) (EGU-based portions of NO_X SIP Call statewide budgets).

[24] For example, sources responsible for over 40% of 2008 emissions reported under the NBTP have either ceased operation or switched from coal combustion to gas or oil combustion since 2008. *See* Post-2008 Changes to Units Reporting Under the NO_X Budget Trading Program (August 2018), available in the docket for this action.

Table 1 shows the portions of the reported seasonal NO_X emissions for each state reported by units that would continue to be subject to part 75 monitoring requirements even if the proposed amendments are finalized and all states choose to revise their SIPs.[25] As indicated in the table, the sources that would continue to report under part 75 account for over 90% of the overall emissions. If a state chooses to revise its SIP to no longer require part 75 monitoring for some sources, then under § 51.121(f)(1) and (i)(1)—which EPA did not propose to amend—the SIP would still have to include provisions requiring all large EGUs and large non-EGU boilers and turbines subject to control measures for purposes of the NO_X SIP Call to submit other forms of information on their seasonal NO_X emissions sufficient to ensure compliance with the control measures. EPA stated the belief that in the context of the substantial compliance margins discussed above, and given the continued availability of part 75 monitoring data from sources responsible for most of the relevant emissions, emissions data from the remaining sources submitted pursuant to other forms of monitoring requirements can provide sufficient assurance that the Rule's overall required emissions reductions will continue to be achieved.

In the proposal's discussion of projected impacts,[26] EPA stated the expectation that the proposed amendments, if finalized, would have no impact on emissions or air quality because no changes would be made to any of the NO_X SIP Call's existing regulatory requirements related to statewide emissions budgets or enforceable mass emissions limits for large EGUs and large non-EGU boilers and turbines.

With respect to cost impacts, EPA expressed the expectation that, if the proposed amendment to monitoring requirements is finalized, at least some states would revise their SIPs to establish alternate monitoring requirements and at least some sources would experience reductions in monitoring costs. EPA indicated that there were approximately 310 existing large EGUs and large non-EGU boilers and turbines in NO_X SIP Call states that could potentially be affected by the proposed amendment to monitoring requirements if all affected states were to revise their SIPs. The discussion also indicated how many of these units used each of the principal monitoring methodologies allowed under part 75 according to the monitoring plans submitted for the units. Specifically, EPA noted that approximately 90 units used monitoring methodologies involving continuous emissions monitoring systems (CEMS) to measure both stack gas flow rate and the concentrations of certain gases in the effluent gas stream, approximately 140 units used methodologies involving gas concentration CEMS but not stack gas flow rate CEMS, and approximately 80 units used non-CEMS methodologies. The proposal noted that it was not possible to predict the amount of the monitoring cost reductions that might eventually result from finalization of the proposed monitoring amendment because states, not EPA, would decide whether to revise the monitoring requirements in their SIPs and because EPA lacks information on the remaining monitoring requirements that sources would face. However, EPA qualitatively discussed how alternate monitoring requirements could result in reduced costs for units currently using the various part 75 monitoring methodologies. For example, some units that currently use part 75 monitoring methodologies involving the use of stack gas flow rate CEMS might be allowed to discontinue use of those CEMS, some units that currently use part 75 monitoring methodologies involving the use of gas concentration CEMS might be allowed to discontinue use of those CEMS, and some units continuing to use one or both types of CEMS might be allowed to perform less extensive data reporting or less comprehensive quality-assurance testing. EPA expressed the expectation that units currently using non-CEMS methodologies under part 75 would experience little or no reduction in monitoring costs as a result of the proposed monitoring amendment.

C. Other Proposed Amendments

In addition to the proposed amendment to the NO_X SIP Call's monitoring requirements discussed in section II.B. of this document, EPA proposed to make several further amendments to the Rule's regulatory text at 40 CFR 51.121 and 51.122 to remove obsolete provisions and clarify the remaining provisions. The proposed revisions also included updates to several cross-references in the CSAPR regulations at 40 CFR 52.38 that refer to an obsolete provision of the NO_X SIP Call regulations. Although EPA proposed to remove or modify numerous provisions of the NO_X SIP Call regulations,[27] the proposal explained that the additional amendments were not intended to substantively alter any currently effective regulatory requirements. Briefly, EPA proposed to:

- Rescind and remove the stayed and superseded findings of good neighbor obligations with respect to the 1997 8-hour ozone NAAQS at § 51.121(a)(2), remove § 51.121(q) staying the now-rescinded findings, and remove obsolete related language in § 51.121(c)(1) and (2);
- Clarify the expression of Phase I and existing final emissions reduction requirements by removing the table of required incremental Phase II emissions reduction amounts at § 51.121(e)(3), adding a column of Phase I budget amounts to the existing table of final budget amounts in § 51.121(e)(2)(i), revising the definitions of ''Phase I SIP submission'' and ''Phase II SIP submission'' at § 51.121(a)(3)(i) and (ii), and making related revisions at § 51.121(b)(1) introductory text and (b)(1)(i);
- Remove § 51.121(e)(4), which governs the former compliance supplement pool;
- Remove § 51.121(e)(5), which sets forth a one-time process for revising the emissions inventories and budgets published as part of the original Rule;
- Remove § 51.121(g)(2)(ii), which contains an obsolete table of baseline emissions inventory information originally intended to help states prepare their required SIP revisions;
- Remove § 51.121(p) and (b)(2), which authorize the use of the former NBTP and other potential interstate trading programs, respectively, as compliance options;
- Make clarifying revisions to § 51.121(r)(2), which sets forth the post-NBTP transition requirements;
- Remove § 51.121(d)(1), which contains obsolete deadlines for Phase I and Phase II SIP submissions, and § 51.121(d)(2), which contains obsolete or duplicative procedural provisions concerning the completeness and format of SIP submissions;
- Remove or update obsolete cross-references in the NO_X SIP Call regulations at §§ 51.121(b)(1)(i), (g)(2)(i) and (r)(1) and (2) and 51.122(c)(1)(ii) and in the CSAPR regulations at

[25] Although the Acid Rain Program does not require units to report NO_X mass emissions specifically, NO_X mass emissions can be calculated from other part 75 data that are required to be reported.

[26] 83 FR at 48761–62.

[27] A redline-strikeout document showing the text of 40 CFR 51.121 and 51.122 with the amendments adopted in this action, which include all the proposed amendments to the NO_X SIP Call regulations with the further revisions discussed in section IV of this document, is available in the docket for this action.

§ 52.38(b)(8)(ii), (b)(8)(iii)(A)(*2*), (b)(9)(ii), and (b)(9)(iii)(A)(*2*); and

- Make clarifying editorial revisions to § 51.121 heading, (b)(1)(ii), (e)(2)(ii)(B) and (E), (f)(2)(i)(B), (f)(2)(ii), (h), (i)(2),(3), and (5), (l)(1) and (2), (m), (n), and (o).

These proposed further amendments as well as EPA's supporting rationales are fully discussed in the proposal.[28] The discussions in the proposal are incorporated herein and are not summarized further in this document except as necessary to respond to comments in sections III.B. through III.D of this document.

D. Public Comment Process

In the proposal, EPA requested comment on the proposed amendment to revise the provision at 40 CFR 51.121(i)(4) to allow states to establish monitoring requirements for large EGUs and large non-EGU boilers and turbines in their SIPs other than part 75 monitoring requirements. With respect to the remaining proposed amendments, EPA made clear that the amendments were not intended to substantively alter existing regulatory requirements and consequently requested comment solely on whether the provisions proposed for removal as obsolete in fact are obsolete and on whether the proposed clarifications in fact achieve clarification. EPA did not reopen for comment any provisions of the existing NO_X SIP Call regulations except the provisions that were proposed to be amended as discussed in the proposal[29] and did not reopen or request comment on amending any other existing regulations. The proposal also provided information on how to request a public hearing. No public hearing was held because none was requested, and the public comment period closed on October 29, 2018.

III. Response to Comments

Commenters on the proposal included states, source owners, industry associations, environmental organizations, and persons commenting as individuals. The comments are available in the docket for this action. In this section, EPA summarizes and responds to the comments regarding the proposed amendments, including requests for clarification. Sections III.A through III.D. address the proposed amendments to the NO_X SIP Call's provisions concerning emissions monitoring requirements, emissions reduction requirements, the baseline emissions inventory table, and post-NBTP transition requirements, respectively.

With respect to the proposed amendments not addressed in sections III.A. through III.D., EPA received no adverse comments or requests for clarification. One commenter stated no objection to or supported most of these amendments individually, and additional commenters expressed general support for all the amendments removing obsolete provisions or all the amendments clarifying the remaining regulations. EPA thanks the commenters for these comments, which are not discussed further in this document.

Some commenters also submitted comments on topics other than the NO_X SIP Call regulations. These comments are outside the scope of the proposal and are not discussed further in this document.

A. Emissions Monitoring Requirements

Comment: Most commenters supported the proposed amendment to the NO_X SIP Call's monitoring requirements. These commenters generally expressed the view that requirements to perform part 75 monitoring solely for purposes of the NO_X SIP Call are no longer necessary to ensure states' compliance with the Rule's emissions reduction requirements. Most of these commenters also generally indicated that allowing the use of alternate monitoring requirements would result in reduced monitoring costs for some sources.

Response: EPA agrees with these comments' support for the proposed amendment to the Rule's monitoring requirements.

Comment: Some commenters, while generally supporting the proposed monitoring amendment, stated that EPA should also make further amendments to the NO_X SIP Call's monitoring provisions to authorize particular forms of alternate monitoring requirements. Specifically, two commenters requested an amendment providing that, if a demonstration is made that emissions from a state's large non-EGU boilers and turbines ''will not exceed the [emissions] budget . . . established'' for such sources, then those sources would be allowed to determine reported NO_X emissions according to a methodology based on the use of emission factors—that is, factors approved as estimates of the quantity of NO_X emitted per unit of fuel combusted—and information on fuel consumption. Another commenter requested an amendment to authorize methodologies involving the use of gas concentration CEMS installed and operated in accordance with the provisions of 40 CFR part 60 in addition to the monitoring methodology preferred by the two previously mentioned commenters. Another commenter, without expressing a preference for a particular form of alternate monitoring requirements, recommended that EPA issue model rule language for alternate monitoring requirements that would be approvable in SIP revisions.

Most commenters supporting the proposed monitoring amendment did not request that EPA make further amendments to identify particular permissible alternate monitoring requirements or issue model rule language. One of these commenters specifically recommended that EPA defer to states' choices regarding alternate monitoring requirements to the maximum extent allowable.

Response: EPA disagrees with the comments seeking further amendments to identify specifically permissible alternate monitoring requirements or issue model rule language and agrees with the comments supporting the monitoring amendment as proposed without such further amendments. Upon finalization of the proposed amendment to the NO_X SIP Call regulations making the inclusion of part 75 monitoring requirements in SIPs optional rather than mandatory, states would have the flexibility to establish their own preferred forms of monitoring requirements for NO_X SIP Call purposes, subject to the existing general provisions at § 51.121(i) introductory text and (i)(1) concerning SIP monitoring requirements—provisions that EPA did not propose to amend. Under the general monitoring provisions, which closely parallel the longstanding provisions concerning SIP source surveillance requirements at 40 CFR 51.210 and 51.211, each SIP revision must provide for monitoring the status of compliance with any control measures adopted to achieve the NO_X SIP Call's emissions reduction requirements, and the monitoring must be sufficient to determine whether sources are in compliance with the control measures. Nothing in these

[28] 83 FR at 48758–61.

[29] Regulatory findings and requirements that EPA did not propose to substantively amend include (but are not limited to) the findings of good neighbor obligations with respect to the 1979 1-hour ozone NAAQS, the requirements for SIPs to contain control measures addressing these obligations, the final NO_X budgets, the requirement for enforceable limits on seasonal NO_X mass emissions for large EGUs and large non-EGU boilers and turbines where states have included control measures for these types of sources in their SIPs, the requirement for states to adopt replacement control measures into their SIPs to achieve the emissions reductions formerly projected to be achieved by the NBTP, and the general requirements for enforceability and for monitoring of the status of compliance with the control measures adopted.

general monitoring provisions precludes the commenters' preferred forms of monitoring requirements where such requirements are shown to be sufficient to meet these criteria. Thus, the further amendments suggested by the commenters are unnecessary, because where a state agrees that the commenters' preferred forms of monitoring requirements are appropriate, the state may obtain approval of those requirements simply by submitting a SIP revision that adopts those requirements and demonstrating that the revision satisfies the general monitoring provisions and does not conflict with any other applicable CAA requirement.[30] For the same reasons that EPA considers it reasonable under current circumstances to make part 75 monitoring optional rather than mandatory for NO_X SIP Call purposes (as discussed in section II.B. of this document), EPA also considers it reasonable to defer to states' choices regarding alternate monitoring requirements for NO_X SIP Call purposes to the extent consistent with the general monitoring provisions at § 51.121(i) introductory text and (i)(1).

In addition, EPA believes that inclusion of the suggested further amendments would not be particularly useful in providing certainty of the approvability of any specific state regulation implementing the commenters' preferred forms of monitoring requirements. Notwithstanding any endorsement of a particular overall monitoring approach that EPA might include in the regulations, given the need to satisfy the NO_X SIP Call's general monitoring provisions just discussed, EPA would still need to individually review the specific alternate monitoring requirements in each SIP revision to support a determination that the monitoring is sufficient to ensure compliance with the NO_X SIP Call's emissions reduction requirements. For example, EPA would need to consider whether each regulation contains adequate provisions to avoid gaps in required monitoring and whether a regulation following an emission factor approach employs emission factors that are designed to avoid any bias toward understatement of emissions. Approval of each SIP revision would also be subject to notice-and-comment procedures. While in theory EPA could provide greater certainty of the approvability of certain forms of alternate monitoring requirements by issuing model rule language, EPA believes issuance of such language in this instance is neither necessary nor consistent with EPA's general intent of deferring to states' preferences regarding alternate monitoring requirements for NO_X SIP Call purposes.

Comment: One commenter stated that amending the NO_X SIP Call regulations to allow sources that currently monitor using CEMS to switch to alternate monitoring methods would be inconsistent with CAA section 110(l), 42 U.S.C. 7410(l), known as the ''anti-backsliding'' provision, which prohibits EPA from approving any implementation plan revision that would interfere with any applicable requirement under the CAA. The commenter stated that effective and accurate emissions monitoring is needed to protect against backsliding and that allowing sources to use monitoring approaches less effective than CEMS monitoring would be inconsistent with section 110(l) because it would deprive communities and regulators of timely or reliable emissions information needed to identify possible violations of emissions standards and to facilitate enforcement actions.

Response: EPA disagrees with this comment. As a preliminary matter, EPA notes that CAA section 110(l) applies to EPA actions determining to approve implementation plan revisions, not other EPA actions that might affect the matters that are required to be addressed through such implementation plan revisions. Thus, this action to amend the NO_X SIP Call regulations is not subject to section 110(l). At the same time, no Agency-issued regulation can negate or otherwise modify the Congressionally-established prohibition in section 110(l) against approval of implementation plan revisions that would permit backsliding. For this reason, notwithstanding the content of any amendment to the NO_X SIP Call regulations finalized in this action, approval of any SIP submissions made in response to such an amendment will necessarily still be subject to anti-backsliding requirements under section 110(l).

Substantively, the proposed amendment to monitoring requirements is not inconsistent with the purpose of section 110(l) because there is no reason to expect that a SIP submission seeking only to revise monitoring requirements for NO_X SIP Call purposes would result in increased emissions or otherwise interfere with any other CAA requirement, in light of the criteria for approval of such a SIP submission. That is, the amendments proposed for this action make no changes to the NO_X SIP Call's existing regulatory requirements related to statewide emissions budgets or enforceable mass emissions limits for large EGUs and large non-EGU boilers and turbines. As discussed in response to a previous comment, under § 51.121(i) introductory text and (i)(1) any alternate monitoring requirements approved into a SIP for NO_X SIP Call purposes must be sufficient to determine whether the state's sources are in compliance with the control measures adopted to meet the Rule's emissions requirements. Given continued implementation of SIP requirements governing the unchanged amounts of allowable emissions, accompanied by replacement monitoring requirements sufficient to ensure compliance with the unchanged emissions requirements, a SIP revision adopted in response to the proposed amendments would not be expected to result in increases in emissions that could interfere with other statutory or regulatory requirements.

The commenter's suggestion that CEMS emissions data provided pursuant to NO_X SIP Call requirements is necessary to provide emissions information to identify violations of and enforce other emissions standards is outside the scope of the proposal. The NO_X SIP Call's monitoring requirements were promulgated to provide monitoring information sufficient to ensure compliance with the control measures adopted to achieve the Rule's emissions reduction requirements.[31] Monitoring requirements to ensure compliance with other emissions requirements are generally established as part of the regulations that establish each specific emissions requirement or through monitoring-focused regulations such as the source surveillance regulations at 40 CFR part 51, subpart K, or the compliance assurance monitoring regulations at 40 CFR part 64. Any concerns about the adequacy of the monitoring requirements established under other regulations would be properly raised as comments in the actions promulgating those regulations or as requests for new rulemaking, not as comments on this action addressing monitoring requirements under the NO_X SIP Call regulations. In the proposal for this action, EPA did not propose to alter any monitoring requirements under any

[30] EPA notes that for purposes of demonstrating that the replacement monitoring requirements would be sufficient to ensure compliance with the emissions requirements, a state generally would be able to cite the same types of data that EPA presented in the proposal to support the proposed amendment to the NO_X SIP Call's monitoring requirements.

[31] *See* 83 FR at 48757.

regulations other than the NO_X SIP Call regulations.

Comment: One commenter stated that amending the NO_X SIP Call regulations to allow sources that currently monitor using CEMS to switch to alternate monitoring methods would be inconsistent with CAA section 504(b), 42 U.S.C. 7661c(b), which authorizes EPA to prescribe monitoring requirements for the operating permits that certain sources are required to obtain pursuant to CAA title V. The commenter cited a portion of the provision stating that ''continuous emissions monitoring need not be required if alternative methods are available that provide sufficiently reliable and timely information for determining compliance'' and stated that because CEMS monitoring is the most reliable and timely monitoring method for determining compliance with NO_X emissions limits, it would be unreasonable and inconsistent with section 504(b) for EPA to allow sources which already have CEMS equipment installed to use less reliable and timely monitoring approaches.

Response: EPA disagrees with this comment. While CAA section 504(b) provides EPA with authority to prescribe monitoring requirements for title V operating permits, it does not require EPA to exercise that authority in any particular situation and hence does not impose any statutory requirement applicable to this action. Further, even accepting for purposes of argument the comment's premise that the conditions that would apply to an exercise of EPA's authority under section 504(b) should also apply to EPA's establishment of monitoring requirements for NO_X SIP Call purposes, the proposed monitoring amendment is neither unreasonable nor inconsistent with those conditions. As noted in the comment, section 504(b) explicitly provides that EPA need not exercise its authority under the section so as to require CEMS in circumstances where alternate monitoring methods sufficient to determine compliance are available. In the proposal, EPA presented recent emissions data and expressed the view that, given the current substantial margins by which the sets of large EGUs and large non-EGU boilers and turbines in all NO_X SIP Call states are complying with the relevant portions of the statewide emissions budgets as well as the fact that most of the relevant emissions will continue to be monitored according to part 75 under other programs, monitoring of the remaining emissions using non-part 75 approaches can now provide sufficient assurance that the Rule's required emissions reductions will continue to be achieved.[32] The commenter does not challenge EPA's assessment. EPA's rationale for proposing the amendment closely parallels and is fully consistent with the conditions set forth in section 504(b) for the possible establishment of monitoring requirements other than CEMS monitoring requirements.

Moreover, neither of the commenter's stated reasons for suggesting that it would be unreasonable or inconsistent with section 504(b) for EPA to allow the use of non-CEMS approaches is compelling. The first stated reason—that CEMS-based monitoring approaches would provide the *most* reliable and timely information for determining compliance with NO_X emission limits—is itself inconsistent with the statutory text which, as just discussed, explicitly indicates the potential acceptability of non-CEMS monitoring approaches that provide *sufficient* reliability and timeliness of information for determining compliance. The second stated reason—that the sources in question already have CEMS equipment installed—is incorrect for some of the sources potentially affected by the monitoring amendment and materially incomplete for all of them. The set of large EGUs and large non-EGU boilers and turbines subject to the NO_X SIP Call's ongoing requirements discussed in this document includes both existing and new units. Some new units that would need to install CEMS equipment if required to monitor under part 75 might not need to install some or all of that CEMS equipment if part 75 monitoring were not required for NO_X SIP Call purposes. Further, as discussed in the proposal, even for a source that already has CEMS equipment installed, the source's ongoing operating costs to monitor using the installed CEMS equipment could be higher than the source's ongoing operating costs if the source were to switch to a non-CEMS monitoring approach.[33] Besides the factor of whether non-CEMS monitoring approaches that provide sufficiently reliable and timely information for determining compliance are available, the text of section 504(b) does not specify or limit other factors that EPA may consider when applying its authority under the section. Thus, it is neither unreasonable nor inconsistent with section 504(b) for EPA to consider the likelihood that some sources would incur lower monitoring costs if allowed to use non-CEMS monitoring approaches for NO_X SIP Call purposes.

Comment: One commenter summarized several provisions of CAA section 110(a), 42 U.S.C. 7410(a), concluding with the interpretation that ''a bedrock requirement for any implementation plan is for emissions monitoring requisite to ensure attainment and maintenance of the NAAQS.'' The commenter further stated that the current network of ambient air quality monitors is ''not robust enough to adequately assess levels of [ozone and particulate matter] in ambient air'' and cited a study concerning satellite-based measurements of ambient air quality. The commenter concluded that ''[g]iven this level of under-assessment of pollution problems and dramatic[ ] undercounting of nonattainment issues,'' the proposed amendment to allow states to establish alternate emissions monitoring requirements ''is wholly inconsistent with the Clean Air Act's requirements.''

Response: EPA disagrees that the proposed amendment to the NO_X SIP Call regulations would be inconsistent with the statutory requirements under CAA section 110(a). The comment conflates the statutory provision authorizing EPA to prescribe emissions monitoring requirements for individual sources under CAA section 110(a)(2)(F) with the general requirement for ambient air quality monitoring under CAA section 110(a)(2)(B). Contrary to the commenter's interpretation of CAA section 110(a), the data used to determine whether air quality in a given area meets the ozone or $PM_{2.5}$ NAAQS are the data obtained through the ambient air quality monitoring network, not the data obtained through source emissions monitoring. Similarly, assessments of whether the emission control measures in effect are collectively sufficient to ensure attainment and maintenance of those NAAQS are made using monitored ambient air quality data or projected ambient air quality data (which necessarily reflect projected, not monitored, source emissions data). The amendments proposed for this action would not alter any regulatory requirements concerning ambient air quality monitoring, and comments on this topic are outside the scope of the proposal.

As discussed in response to a previous comment, the originally intended purpose served by the emissions monitoring requirements under the NO_X SIP Call was to ensure compliance with the control measures

[32] 83 FR at 48757–58.

[33] 83 FR at 48761. Several commenters also discussed the significance of the operating and maintenance costs that are incurred to comply with monitoring requirements. *See* comments of North Carolina, Alcoa, Citizens Energy, Council of Industrial Boiler Owners, and Virginia Manufacturers Association.

adopted to achieve the Rule's emissions reduction requirements, not to ensure attainment and maintenance of the NAAQS. Amendment of the NO_X SIP Call as proposed for this action would not alter the provisions at § 51.121(i) introductory text and (i)(1) that set forth the ongoing general requirement for SIPs to include emissions monitoring sufficient for this purpose. The amendment would simply expand the options available to states for addressing the ongoing general requirement by eliminating the additional specific requirement at § 51.121(i)(4) for part 75 monitoring by large EGUs and large non-EGU boilers and turbines. Like the NO_X SIP Call's initial monitoring requirements, the Rule's monitoring requirements as amended would be fully consistent with CAA section 110(a)(2)(F), which authorizes EPA to prescribe emissions monitoring and reporting SIP requirements that may include requirements for ''correlation of such [emissions] reports by the State agency with any emission limitations or standards'' established under the CAA.

Comment: One commenter discussed the data EPA presented in the proposal regarding recent emissions reported by the sources that would have been subject to the former NBTP. While not disputing EPA's assessment that the data show that the sources in all states subject to the NO_X SIP Call are currently complying with the assigned portions of their respective statewide budgets by substantial margins, the commenter asserted that EPA's reliance on the data to support the proposed amendment to the Rule's monitoring requirements is misguided. The commenter questioned the relevance of EPA's assessment that non-part 75 monitoring by the sources not subject to part 75 monitoring requirements under other programs could now provide assurance of continued compliance with the NO_X SIP Call's emissions reduction requirements, suggesting that EPA should instead consider emissions targets more stringent than the Rule's existing budgets.

With regard to EPA's assessment that the substantial majority of emissions from large EGUs and large non-EGU boilers and turbines would continue to be monitored according to part 75 under other programs, the commenter observed that in certain states, the emissions from the subset of large EGUs and large non-EGU boilers and turbines potentially affected by the proposed monitoring amendment can be significant relative to the emissions from the remaining large EGUs and large non-EGU boilers and turbines that must continue to monitor their emissions under part 75 for other programs. Based on this observation, the commenter concluded that, in these states, allowing the potentially affected sources to monitor using non-CEMS methodologies ''will notably degrade the overall NO_X emissions data'' from the sets of large EGUs and large non-EGU boilers and turbines in the states. The commenter also stated that the total amount of seasonal NO_X emissions from the potentially affected sources—approximately 15,000 tons in the 2017 ozone season—is ''not trivial,'' but is significant in an absolute sense regardless of its relation to the amount of emissions from the sources that would still be subject to part 75 monitoring requirements under other programs. Noting that annual emissions of 100 tons can trigger classification of certain types of new or modified sources as ''major sources'' under other CAA programs, the commenter suggested that allowing sources that collectively produce 15,000 tons of seasonal NO_X emissions to stop using CEMS is comparable to excusing as many as 360 major sources from requirements to use NO_X CEMS under other programs.

Response: EPA continues to believe that the emissions data presented in the proposal provide compelling support for the proposed amendment to the NO_X SIP Call's emissions monitoring requirements. EPA disagrees with the commenter's suggestion that in evaluating possible changes to monitoring requirements under the NO_X SIP Call, rather than assessing whether alternate forms of monitoring would be sufficient to ensure compliance with the Rule's existing emissions reduction requirements, EPA should instead consider whether the alternate monitoring requirements would be sufficient to ensure compliance with more stringent emissions targets. As discussed in response to a previous comment, the Rule's monitoring requirements were established to provide monitoring information sufficient to ensure compliance with the control measures adopted to achieve the Rule's required emissions reductions, and monitoring requirements to ensure compliance with other emissions requirements are established in other regulations. Comments concerning whether the Rule's existing emissions reductions requirements are sufficiently stringent are outside the scope of the proposal. EPA did not propose to substantively alter any regulatory requirements other than the NO_X SIP Call's monitoring requirements.

With regard to the commenter's observations concerning the relative magnitudes of the respective total amounts of emissions from sources potentially affected by the proposed monitoring amendment and other sources in certain states, EPA acknowledges that emissions from the potentially affected sources comprise larger shares of the total emissions from large EGUs and large non-EGU boilers and turbines in some states than others but disagrees with the suggestion that this fact should foreclose the possibility of allowing monitoring flexibility for NO_X SIP Call purposes. According to the recent emissions data presented in the proposal [34] and reproduced in Table 1 in section II.B. of this document, for six of the states identified in the comment—Alabama, Maryland, New Jersey, New York, South Carolina, and Tennessee—the total amount of emissions from the state's potentially affected sources was from 19% to 30% of the total amount of emissions from the state's remaining large EGUs and large non-EGU boilers and turbines, and for the last identified state—Delaware—the emissions from the state's potentially affected sources exceeded the emissions from the state's remaining large EGUs and large non-EGU boilers and turbines. However, even accepting the commenter's premise that allowing the potentially affected sources in these states to switch from CEMS methodologies to non-CEMS methodologies would reduce the accuracy of the total reported amounts of emissions from large EGUs and large non-EGU boilers and turbines, EPA believes that the compliance margins in these states are large enough that there would still be sufficient assurance that the NO_X SIP Call's emissions reduction requirements would continue to be achieved. In each of these states (as well as all the other states subject to the NO_X SIP Call), the emissions data in Table 1 indicate that, assuming no increase in the total emissions from the sources in the state that would continue to be subject to part 75 monitoring under other programs, the total emissions from the state's potentially affected sources could increase at least eightfold without causing the total emissions from the state's large EGUs and large non-EGU boilers and turbines to exceed the relevant portion of the statewide emissions budget.[35] Thus, again

[34] *See* 83 FR at 48758 (Table 1).

[35] The recent compliance margins for the individual NO_X SIP Call states indicated by the data in Table 1 range from 8.6 times to over 300 times the total reported emissions from the respective states' sets of potentially affected sources. For example, for Alabama, the data in Table 1 indicate a compliance margin of 16,420 tons (25,497 − 9,077 = 16,420), which is 8.6 times the reported emissions

Continued

assuming no increase in the total emissions from the sources in the state that would continue to be subject to part 75 monitoring under other programs, even if the total reported emissions data for the set of potentially affected sources in a state in some future ozone season were to understate the true emissions data because of less accurate measurements made using non-CEMS methodologies, in order for the total reported emissions data to incorrectly indicate compliance for the state when the true emissions data would indicate non-compliance, the cumulative measurement errors causing understatement of the true data—that is, the differences between the reported emissions data values and the true emissions data values for each source—would have to be several times larger than the reported data values.[36] The commenter does not suggest, and EPA does not believe, that the accuracy of non-CEMS monitoring approaches would be so poor as to allow such a scenario to occur. Moreover, if the commenter believes that the specific alternate monitoring approaches included in a particular state's SIP revision submitted for EPA's approval would provide insufficiently accurate data to ensure continued compliance with the control measures adopted in the state's SIP for NO_X SIP Call purposes, the notice-and-comment process for approval of the SIP revision would provide an opportunity for the commenter to raise that concern.

With regard to the commenter's observations concerning the significance of the total seasonal NO_X emissions from the potentially affected sources in an absolute sense, EPA agrees that a 15,000-ton quantity of seasonal NO_X emissions is ''not [a] trivial'' amount but disagrees with the suggestion that this fact should foreclose the possibility of allowing monitoring flexibility for NO_X SIP Call purposes. The proposed amendments would not alter any of the Rule's regulatory requirements concerning permissible amounts of emissions and would not eliminate the requirement for SIPs to provide for monitoring of the emissions from all large EGUs and large non-EGU boilers and turbines sufficient to ensure continued compliance with the Rule's emissions reduction requirements. Nor does EPA agree that allowing non-CEMS monitoring approaches to be used for purposes of demonstrating compliance with control measures adopted under the NO_X SIP Call is comparable to excusing major sources from requirements to monitor using CEMS for other purposes. The amendments proposed for this action are based on EPA's assessment, specific to this action, that under current circumstances monitoring information from some sources other than part 75 monitoring information can now provide sufficient assurance that the NO_X SIP Call's required emissions reductions will continue to be achieved. Where any source is required to monitor using CEMS for another purpose under regulations other than the NO_X SIP Call regulations, the amendments proposed for this action would not affect those requirements.

Comment: One commenter contended that allowing alternate monitoring requirements will lead to increased emissions. The commenter observed that EPA did not know which specific sources might ultimately be allowed to use alternate monitoring methods. According to the commenter, EPA had suggested in the proposal that the potential for increases in pollution resulting from alternate monitoring requirements is merely uncertain, because EPA would not itself relax the requirements but would leave that decision to the states, and the commenter stated it is arbitrary and capricious for EPA to rely on such a claim of uncertainty to avoid assessing the impacts of increased pollution. The commenter contended that EPA had suggested in the proposal that ''systemwide NO_X emissions are low enough that if there are increases in pollution attainment and maintenance [of the NAAQS] might not be threatened.'' The commenter also discussed ozone pollution and the harms it causes to human health and the environment, citing several EPA documents.

Response: EPA does not dispute the commenter's summary of the harms caused by ozone pollution or the correct observation that EPA does not know which specific sources might ultimately be allowed to use alternate monitoring methods (because states, not EPA, will decide whether to revise their SIPs). Otherwise, EPA disagrees with these comments. Relative to part 75 monitoring approaches, non-part 75 monitoring approaches may be expected to provide less detailed monitoring data and require less rigorous quality assurance, with a consequently greater possibility that the total NO_X emissions amount reported by a source for a given ozone season might understate or overstate the source's actual total emissions for that ozone season to some degree. However, there is no reason to expect any approved non-part 75 monitoring methodology either to be systematically biased toward understatement of emissions or to create any incentive leading to increased emissions. EPA was clear in the proposal that no changes to emissions or air quality are expected because no changes are being made to the NO_X SIP Call's emissions requirements.[37] The commenter effectively equates allowing alternate monitoring methods with relaxing emissions requirements, providing no rationale or evidence to support the contention that in the absence of any change in either emissions requirements or the general requirement to monitor emissions, possible changes in just the allowed methods for emissions monitoring under the NO_X SIP Call will lead to increased emissions. EPA continues to believe it is reasonable to assume that under current circumstances where sources are already complying with the NO_X SIP Call's emissions requirements by substantial margins, substitution of one monitoring method for another monitoring method, in the absence of any change in the Rule's emissions requirements, will not cause sources to change their behavior in a way that would affect emissions levels. Moreover, in the event that a particular state's SIP submission were to include a poorly designed alternate monitoring requirement that could lead to systematic understatement of emissions, the SIP approval process—including notice-and-comment procedures—would provide a further safeguard against the possibility of alternate monitoring requirements insufficient to ensure compliance with the Rule's emissions requirements. The commenter appears to incorrectly assume that the amendment in this action would by itself end all EPA oversight of monitoring requirements for NO_X SIP Call purposes and fails to acknowledge the additional safeguard afforded by the SIP approval process.

The commenter's claims regarding suggestions that EPA purportedly made about the supposed possibility of increased emissions misrepresent the proposal. Contrary to the comments, nowhere in the proposal did EPA indicate ''uncertainty'' as to whether the proposed amendments would lead to

from the state's potentially affected sources (16,420 ÷ 1,911 = 8.6).

[36] For illustrative purposes, this example assumes both that the collective emissions from potentially affected sources in a state would increase by the amount necessary to cause non-compliance for the state and that the alternate monitoring methodologies would fail to register the increase in emissions. EPA does not believe these assumptions have a reasonable basis and is using them only to respond to the commenter's concerns regarding accuracy.

[37] 83 FR at 48761.

increased pollution. Rather, as just discussed, EPA explicitly stated that the proposed amendments are expected to have no impact on emissions or air quality. The fact that states, rather than EPA, will decide whether to revise their SIPs to establish alternate monitoring requirements was cited in the proposal as a basis for uncertainty with regard to the potential amount of reductions in monitoring costs, not as a basis for uncertainty with regard to supposed potential increases in emissions.[38] Likewise, nowhere in the proposal did EPA make any suggestion regarding the relationship of supposed potential increases in emissions to the likelihood of attainment or maintenance of any NAAQS. Rather, as an illustration of the magnitude of states' recent margins of compliance with the NO_X SIP Call's emissions reduction requirements, EPA stated only that such compliance would continue to be achieved even if emissions were to increase substantially from current levels, and then proceeded to explain why such increases in emissions in fact are unlikely to occur.[39]

Comment: One commenter suggested that the proposal did not address relevant differences among the states and source types that could be affected by the proposed monitoring amendment. The commenter stated that the proposal failed to identify which sources affected under the NO_X SIP Call do not participate in any CSAPR trading program. Noting that several NO_X SIP Call states are outside the region covered by the various CSAPR trading programs, the commenter asserted that EPA had failed to explain ''why sources in some areas should be allowed to monitor less and pollute more,'' and that ''EPA is thus effectively proposing to end continuous NO_X monitoring for an entire geographic area without discussing the ensuing implications.'' Noting that the NO_X SIP Call applies to both EGUs and non-EGUs while the CSAPR trading programs generally apply only to EGUs, the commenter further asserted that EPA did not ''coherently address the distinction between the *types* of sources'' (emphasis in original) covered by the NO_X SIP Call and the CSAPR trading programs. Repeating the contention that allowing alternate monitoring methods will lead to increased emissions, the commenter suggested that EPA should have evaluated the impacts on regional ozone transport problems of allowing alternate monitoring methods for some states and source types but not others.

[38] 83 FR at 48761.

[39] 83 FR at 48757 & nn.38–39.

Response: EPA disagrees with these comments. Contrary to the commenter's suggestion, the proposal explicitly discussed differences among NO_X SIP Call states concerning whether each state's EGUs are covered by a CSAPR trading program, noting that EGUs in Connecticut, Delaware, Massachusetts, Rhode Island, and the District of Columbia do not participate in any CSAPR trading programs.[40] Likewise, the commenter's assertion that the proposed monitoring amendment would ''end continuous NO_X monitoring for an entire geographic region'' is directly contradicted by information in the proposal: First, by the explanation that most of the EGUs in the five non-CSAPR states will remain subject to part 75 monitoring requirements under the Acid Rain Program;[41] second, by the explanation that most of the emissions from the set of large EGUs and large non-EGU boilers and turbines affected under the NO_X SIP Call come from large EGUs that would continue to monitor their emissions according to part 75 under either the Acid Rain Program or a CSAPR trading program;[42] and third, by the data showing quantitatively that out of the total set of sources subject to the NO_X SIP Call in the five non-CSAPR states, the subset of sources that would continue to be subject to part 75 monitoring requirements under other programs has produced most of the recent emissions.[43]

Contrary to the commenter's assertion that the proposal failed to address the distinction between EGUs and non-EGUs, the proposal explicitly discussed the fact that unlike most EGUs, most non-EGUs affected under the NO_X SIP Call do not participate in a CSAPR trading program or face part 75 monitoring requirements under other programs.[44] The proposal also explicitly noted that although some of the sources potentially affected by the proposed monitoring amendment are large EGUs not subject to the Acid Rain Program or a CSAPR trading program, most of the potentially affected sources are large non-EGU boilers and turbines.[45] The proposal presented recent state-specific emissions data broken out according to whether the emissions came from sources that would continue to be subject to part 75 requirements under other programs or instead came from sources potentially affected by the proposed amendment.[46] The proposal did not further break out the total recent emissions from potentially affected sources into the respective portions from EGUs and non-EGUs because EPA did not see any relevance in whether the NO_X emissions that might be monitored for NO_X SIP Call purposes using methods other than part 75 come from EGUs or from non-EGUs. The commenter has not suggested any reasons why further subcategorization of the emissions information provided in the proposal might be relevant to an evaluation of the proposed monitoring amendment. Nevertheless, to address the comment, EPA notes that large non-EGU boilers and turbines were collectively responsible for 14,860 tons of the total 15,084 tons of seasonal NO_X emissions shown in Table 1 for all units potentially affected by the proposed monitoring amendment, or 98.5% of the total, while large EGUs not required to monitor according to part 75 under the Acid Rain Program or a CSAPR trading program were collectively responsible for 224 tons, or 1.5% of the total.[47]

The comments suggesting that EPA should have evaluated the impacts on regional ozone transport problems of allowing alternate monitoring methods for some states and source types but not others reflect the commenter's unsupported assumption that allowing alternate monitoring methods is equivalent to relaxing emissions requirements. EPA has already rebutted the commenter's assumption in response to a previous comment. Because there is no reason to expect any increase in emissions from the proposed monitoring amendment, there is no reason to evaluate any impacts on regional ozone transport problems of any supposed potential increase in emissions.

Comment: One commenter stated that EPA has not ''identif[ied] any *need* to weaken emission monitoring requirements'' (emphasis in original), has not identified specific complaints

[40] 83 FR at 48756 & nn.26–27. EPA notes that there are currently no large EGUs in the District of Columbia.

[41] 83 FR at 48756 & n.27.

[42] 83 FR at 48758 & n.40.

[43] *See* 83 FR at 48758 (Table 1) (also reproduced as Table 1 in section II.B. of this document). The sum of the emissions shown in Table 1 for the sources that would continue to be subject to part 75 monitoring in the five non-CSAPR states is 1,631 tons. The sum of the emissions shown for the sources potentially affected by the proposed amendment in these states is 654 tons.

[44] 83 FR at 48751–52, 48755–56 & n.23.

[45] 83 FR at 48752.

[46] 83 FR at 48758 (Table 1).

[47] The potentially affected large EGUs are combustion turbines located in non-CSAPR states that serve generators larger than 25 MW and are exempt from the Acid Rain Program because they commenced commercial operation before November 15, 1990, and meet the definition of a ''simple combustion turbine'' in 40 CFR 72.2. There are currently 31 such units, all located in Connecticut, Delaware, or Massachusetts. The individual units are identified in the spreadsheet referenced in note 54 *infra,* available in the docket for this action.

from sources regarding the costs of operating monitoring equipment that has already been installed, and has not sufficiently discussed possible monitoring methodologies or compared their costs. The commenter also stated that allowing alternate monitoring requirements would unfairly advantage new sources over existing sources because the new sources, unlike existing sources, would be allowed ''to both use cheaper, less effective monitoring systems and to get away with emitting more NO_X'' than existing sources.

Response: EPA disagrees with these comments. In the proposal, EPA discussed the opportunity to reduce monitoring costs under the NO_X SIP Call for some sources while continuing to ensure compliance with the Rule's emissions reduction requirements.[48] By definition, a regulatory initiative that reduces overall costs while holding overall benefits constant produces positive net benefits. The commenter has not offered any legal basis or policy rationale supporting the notion that EPA should decline to pursue a regulatory initiative intended to produce positive net benefits simply because the net benefits happen to take the form of a reduction in sources' monitoring costs.

The commenter's suggestion that EPA has presented insufficient evidence to support the existence of monitoring cost reduction opportunities is belied by the information in the proposal, which described the various monitoring methodologies available under part 75 and qualitatively discussed the cost reductions that could be available if the sources using each of those methodologies were to switch to alternate monitoring methodologies.[49] Moreover, all of the comments received on the proposal from source owners and industry associations, as well as most of the comments received from states, agreed that the proposed amendment would make monitoring cost reductions possible for sources in states that choose to revise their SIPs.[50] The commenter asserted that sources had no reason to complain of monitoring costs because they had already installed the necessary CEMS equipment, but as EPA explained in response to a previous comment, this assessment is incorrect as to new sources, because new sources would not yet have installed the CEMS equipment, and materially incomplete as to all sources, because CEMS-related costs include not only equipment installation costs but also ongoing operating costs. EPA sees no reason why, in the absence of any contrary information, more evidence is needed to demonstrate the existence of opportunities for monitoring cost reductions than was already presented in the proposal, as further supported by comments.

With respect to quantification of the potential reductions in monitoring costs, EPA explained in the proposal that because states, not EPA, would decide whether to revise the monitoring requirements in their SIPs and because EPA lacked complete information on the remaining monitoring requirements that the sources would face, it was not possible to predict the amount of monitoring cost reductions that could occur following finalization of the proposed monitoring amendment.[51] EPA still lacks information on the remaining monitoring requirements that sources will face but received comments indicating some likelihood that at least six states would revise their SIPs following finalization of the proposed monitoring amendment. The states' comments make it possible to estimate a potential range of monitoring cost reductions that could occur if these states were to adopt some of the changes in monitoring requirements that EPA considers most likely. EPA's estimates are provided in section V of this document.

Finally, the commenter's suggestion that the proposed monitoring amendment would unfairly advantage new sources over existing sources lacks any support. The NO_X SIP Call's current requirements for part 75 monitoring apply to both existing and new sources, and upon finalization of the proposed monitoring amendment, states' flexibility to establish alternate monitoring requirements will likewise apply to both existing and new sources. Commenters have not suggested any reason to believe that states will choose to exercise this new flexibility in a manner that discriminates among their existing and new sources in terms of the prospective monitoring requirements established in their SIPs, and if the commenter is suggesting that EPA should require new sources to incur certain capital expenditures in the future simply because existing sources incurred those same capital expenditures in the past, EPA disagrees. Further, the commenter's assertion that the monitoring amendment will allow new sources to ''get away with emitting more NO_X'' again rests on the commenter's unsupported assumption that allowing alternate monitoring methods is equivalent to relaxing emissions requirements. EPA has already rebutted the commenter's assumption in response to a previous comment. EPA also reiterates that the proposed monitoring amendment would not change any other emissions or monitoring requirements applicable to either existing or new sources under regulations other than the NO_X SIP Call, including requirements that may be more stringent for new sources than existing sources.

Comment: One commenter discussed the superiority of CEMS methodologies compared to non-CEMS monitoring methodologies in terms of the timeliness and reliability or accuracy of the emissions data collected, particularly with respect to NO_X emissions, and cited various EPA documents in support. The commenter stated that EPA ''should be enhancing the use of CEMS in emissions measurements'' instead of allowing monitoring flexibility. In particular, the commenter stated that the continued use of CEMS is necessary to ensure compliance with the Chesapeake Bay Total Maximum Daily Load (TMDL) for nitrogen established under the Clean Water Act. In support of this comment, the commenter summarized the role of atmospheric deposition as a contributor of nitrogen to Chesapeake Bay, citing studies by EPA and others. The commenter also noted that the plan for achieving the TMDL includes commitments from EPA to reduce atmospheric deposition through implementation of rules addressing CAA requirements, including the NO_X SIP Call, and stated that EPA must maintain or strengthen air regulations in order to meet its commitments. The commenter stated that without accurate monitoring, states and EPA ''will not know whether the reductions necessary to attain the Bay TMDL goals by 2025 are actually being met.''

Response: EPA agrees that CEMS methodologies are often the preferred monitoring approaches for ensuring compliance with particular emissions requirements but disagrees that the acknowledged superiority of CEMS methodologies for some purposes should foreclose the possibility of allowing monitoring flexibility for NO_X SIP Call purposes where other monitoring methods would be sufficient to ensure continued achievement of the Rule's emissions reduction requirements. Likewise, EPA does not dispute the commenter's summary regarding the Chesapeake Bay TMDL

[48] 83 FR at 48761–62.

[49] 83 FR at 48761 & nn.53–54.

[50] *See* comments from Indiana, Michigan, North Carolina, Ohio, South Carolina, Alcoa, Citizens Energy, Council of Industrial Boiler Owners, Illinois Environmental Regulatory Group, Ohio Manufacturers Association, Virginia Manufacturers Association, and West Virginia Manufacturers Association, available in the docket for this action.

[51] 83 FR at 48761.

and EPA's reliance on the NO_X SIP Call's emissions reductions to reduce atmospheric deposition contributing nitrogen to the Bay but disagrees that those facts suggest that compliance with the Rule's emissions reduction requirements must be determined using any particular monitoring approach. As discussed in response to a previous comment, the NO_X SIP Call's existing monitoring requirements were established to provide monitoring information sufficient to ensure compliance with the control measures adopted to achieve the Rule's required emissions reductions, and monitoring requirements to ensure compliance with other emissions requirements are established in other regulations. Comments concerning whether the NO_X SIP Call's existing emissions reductions requirements are sufficiently stringent to address other environmental objectives, including achievement of the Chesapeake Bay TMDL, are outside the scope of the proposal. EPA did not propose to substantively alter any regulatory requirements other than the NO_X SIP Call's monitoring requirements.

Comment: One commenter supported a narrower amendment to the NO_X SIP Call's monitoring requirements than EPA proposed. Specifically, the commenter supported an amendment that would allow states to eliminate the requirements for reporting emissions data to EPA under part 75 but would not allow the use of substantively different monitoring methodologies for collecting emissions data. The commenter objected to allowing sources that currently monitor emissions using CEMS to use other monitoring methodologies because, unlike CEMS methodologies, non-CEMS methodologies do not allow for accurate and timely determinations of compliance with or violations of short-term emission limits. The commenter also expressed the expectation that if the proposed amendment to emissions monitoring requirements is finalized, some states would be required to revise their SIPs to establish less stringent monitoring requirements because of provisions in state law barring the states from imposing requirements on sources that exceed minimum Federal requirements.

Response: The comment expressing concern that non-CEMS methodologies are less useful than CEMS methodologies for determining compliance with emissions requirements other than the NO_X SIP Call's emissions requirements is outside the scope of the proposal. As discussed in response to a previous comment, the NO_X SIP Call's existing monitoring requirements were established to provide monitoring information sufficient to ensure compliance with the control measures adopted to achieve the Rule's required emissions reductions, and monitoring requirements to ensure compliance with other emissions requirements are established in other regulations. The NO_X SIP Call does not require states to impose short-term emissions limits on their sources, and EPA did not propose to substantively alter any regulatory requirements other than the NO_X SIP Call's monitoring requirements.

The comment suggesting that some NO_X SIP Call states would be required under state law to revise their SIPs if the proposed monitoring amendment is finalized has no bearing on this action. EPA's proper focus in this action is whether the proposed amendment to allow alternate monitoring requirements in SIPs is appropriate under the CAA. Questions of whether and how state law provisions might affect the decisions of individual states to adopt alternate monitoring requirements allowed under the amendment are outside EPA's purview.

Comment: One commenter stated that allowing sources that currently monitor emissions for NO_X SIP Call purposes with CEMS methodologies to instead monitor their emissions with non-CEMS methodologies would result in a loss of data resolution that would make it more difficult to understand the impacts of the sources' emissions on air quality in other states. The commenter stated that, with less detailed emissions data, it would be more difficult for states to work together to develop regionally consistent approaches for addressing good neighbor obligations with respect to the 2015 ozone NAAQS. The commenter also requested that EPA identify the specific units whose monitoring requirements could potentially be altered by states if the proposed monitoring amendment is finalized, as well as the locations of the units.

Response: EPA disagrees that allowing the use of alternate monitoring requirements for NO_X SIP Call purposes would materially impact the ability of states to work together to address their good neighbor obligations with respect to the 2015 ozone NAAQS in a regionally consistent manner. As discussed in section II.B. of this document, if the proposed amendment is finalized, over 90% of the emissions from the set of NO_X SIP Call large EGUs and large non-EGU boilers and turbines would still be monitored according to part 75 under other regulations if the relative proportions shown for 2017 in Table 1 continue into the future. In addition, the potentially affected sources in states that choose to revise their SIPs would still need to provide emissions monitoring information for each ozone season sufficient for the state to demonstrate compliance with the Rule's emissions reduction requirements. The commenter has not explained the purpose for which the enhanced data resolution provided by part 75 monitoring is desired. In any event, EPA notes that projected hourly emissions data for use in air quality modeling could be prepared based on the intra-year time patterns in the extensive historical emissions data reported by the sources for periods while the sources have been subject to part 75, because those data would remain available even if hourly emissions data are no longer reported in the future for some of these sources. As indicated in Table 1, the total amount of recent seasonal NO_X emissions from the units that could potentially switch from part 75 monitoring approaches to non-part 75 monitoring approaches was approximately 15,000 tons during the 5-month ozone season, which by extrapolation suggests possible annual emissions of roughly 36,000 tons. By comparison, the most recent National Emissions Inventory (for 2014) indicates that for the set of NO_X SIP Call states, the total amount of annual NO_X emissions from all types of stationary sources—that is, not just the large EGUs and large non-EGU boilers and turbines currently subject to part 75 monitoring requirements under the NO_X SIP Call—was over 2,000,000 tons, and the total amount of annual NO_X emissions from all stationary and mobile sources was over 5,000,000 tons.[52] Thus, the NO_X SIP Call units potentially affected by the proposed amendment appear to be responsible for roughly 2% of the total stationary source emissions and less than 1% of the total stationary and mobile source emissions from NO_X SIP Call states. Given the small percentages of the relevant overall emissions inventory represented by the large non-

[52] *See* state_tier1_caps.xlsx, available at *https://www.epa.gov/air-emissions-inventories/air-pollutant-emissions-trends-data* (follow the link for State Average Annual Emissions Trend) and in the docket for this action. The total amount of stationary and mobile source emissions can be obtained from the spreadsheet by filtering column B to exclude all states except the 21 NO_X SIP Call jurisdictions, filtering column D to exclude ''prescribed fires'' and ''wildfires,'' filtering column E to exclude all pollutants except NO_X, and then summing the 2014 emissions inventory amounts in column Y for all remaining line items shown. The total amount of stationary source emissions can be obtained in the same way after further filtering column D to exclude ''highway vehicles'' and ''off-highway.''

EGU boilers and turbines potentially affected by the monitoring amendment proposed for this action, EPA expects that air quality modeling results and analyses of interstate ozone transport would not be materially affected by differences in the intra-year patterns of the projected hourly emissions data for these sources.

With respect to the commenter's request for the identities and locations of units potentially affected by the proposed monitoring amendment—in other words, large non-EGU boilers and turbines as well as large EGUs that are subject to the NO_X SIP Call but not the Acid Rain Program or a CSAPR trading program—EPA notes that the requested information is already publicly available in the database of reported part 75 emissions data accessible through the Agency's website.[53] The database identifies each individual unit that has reported according to part 75 and provides the unit's state, county, latitude, and longitude. The database also indicates the regulatory programs for which the data have been reported, using the code ''SIPNO_X'' to indicate where a unit has reported seasonal NO_X mass emissions data for purposes of the NO_X SIP Call but not for purposes of the seasonal NO_X trading programs established under CAIR, the original CSAPR, and the CSAPR Update. For the convenience of the commenter and others who might be similarly interested, EPA has extracted this information from the database into a spreadsheet which has been added to the docket for this action.[54]

B. Emissions Reduction Requirements

Comment: One commenter stated it had no objection to the proposed revisions to the provisions expressing the NO_X SIP Call's emissions reduction requirements to the extent that the revisions do not substantively adjust the states' budgets.

Response: EPA thanks the commenter for this comment.

Comment: One commenter agreed with EPA's objective of clarifying and simplifying the provisions describing the NO_X SIP Call's emissions reduction requirements but offered suggestions for doing so in ways that differed in some respects from the proposed amendments. First, the commenter suggested replacing the terms ''budget'' and ''NO_X budget'' with a single term such as ''NO_X ozone season budget'' both for consistency and to clarify that the budgets apply to seasonal rather than annual emissions. The commenter also suggested that EPA specify that the final budgets apply starting in 2007 and define the term ''ozone season'' in the regulations. Finally, the commenter suggested that all references to the Phase I budgets could be removed from the regulations because these budgets no longer have any substantive effect.

Response: EPA agrees with most of the commenter's suggestions. In particular, EPA agrees that the regulations would be clarified by consistently using the term ''NO_X ozone season budget'' throughout § 202F;51.121, specifying that the final budgets apply starting in 2007, and documenting the definition used for the term ''ozone season.'' Extending the commenter's suggestions, EPA believes the regulations would be further clarified by indicating that other emissions amounts described in the regulations are also ozone season emissions and documenting the definition used for the term ''nitrogen oxides'' or ''NO_X.'' The specific changes from proposal that are being adopted in response to the commenter's suggestion are described in section IV of this document.

Although EPA agrees with the commenter's observation that the Phase I budgets no longer have any substantive regulatory effect, EPA disagrees with the suggestion to remove all references to these budgets from the regulations. All but one of the states subject to the NO_X SIP Call as implemented was required to adopt a SIP revision designed to comply with a Phase I budget, and some of the control measures adopted in those SIP revisions (such as measures to reduce emissions from cement kilns or stationary internal combustion engines) continue to be implemented as approved SIP provisions. While these control measures now address requirements to comply with the final budgets rather than the Phase I budgets, EPA considers it reasonable to retain the Phase I budgets in the regulations (and to specify their years of applicability) to document and facilitate understanding of both the state regulatory actions that originally adopted the measures and the EPA actions that approved the measures into the SIPs.

C. Baseline Emissions Inventory Table

Comment: One commenter objected to the proposed removal of the baseline emissions inventory table in § 51.121(g)(2)(ii), requesting that the table be retained (with any necessary updates) for use in implementing the provisions at § 51.121(f)(2) that require enforceable limits on seasonal NO_X mass emissions from large EGUs and large non-EGU boilers and turbines. The text of § 51.121(f)(2)(ii), which EPA has not proposed to substantively amend, contains the phrase ''the total NO_X emissions projected for such sources by the State pursuant to paragraph (g) of this section.'' The commenter interprets this phrase as referring to amounts of emissions that the commenter believes either are or should be shown in the baseline emissions inventory table in § 51.121(g)(2)(ii).

Response: EPA disagrees with this comment, which appears to arise from a misinterpretation of the reference to ''paragraph (g)'' in § 51.121(f)(2)(ii). The various subparagraphs of § 51.121(g) describe or implicate two different types of projected 2007 emissions amounts. The first type is the baseline *pre-control emissions amounts projected by EPA* to represent emissions absent the reductions required by the NO_X SIP Call. The second type is the *post-control emissions amounts projected by states* to represent emissions following implementation of the control measures adopted in their SIPs. The table in § 51.121(g)(2)(ii) that EPA proposed to delete was intended to contain[55] the first type of emissions amount—specifically, the pre-control emissions amounts projected by EPA for all sources[56] in all sectors. In contrast, the phrase ''the total NO_X emissions projected for such sources[57] by the State pursuant to paragraph (g) of this section'' in § 51.121(f)(2)(ii) refers to the second type of emissions amount—specifically, the post-control emissions amounts projected by states for their

[53] *See https://ampd.epa.gov/ampd.*

[54] *See* Existing Units Potentially Affected by the NO_X SIP Call Monitoring Amendment (December 2018), available in the docket for this action. EPA acknowledges that the database does not differentiate between two sets of units for which the SIPNO_X code is used: (1) Large EGUs and large non-EGU boilers and turbines that are described in § 51.121(i)(4) and are potentially affected by the amendments in this action, and (2) other units that are not described in § 51.121(i)(4) and therefore are not affected by the amendments in this action, but that nevertheless monitor according to part 75 for NO_X SIP Call purposes pursuant to requirements in their states' SIPs. The spreadsheet in the docket includes only units in the first set.

[55] As noted in the proposal, because of an error setting out the regulatory text for certain NO_X SIP Call amendments finalized in 2000, the current table incorrectly shows the potential *post-control* emissions amounts that EPA projected for use in setting the states' amended statewide emissions budgets rather than the amended *pre-control* emissions amounts as intended. *See* 83 FR at 48760 & n.48.

[56] The ''EGU'' and ''non-EGU'' columns of the table in § 51.121(g)(2)(ii)—both the original version showing EPA's projections of pre-control emissions and the incorrectly amended version showing EPA's projections of post-control emissions—include emissions amounts for *all* EGU and non-EGU point sources, not just large EGUs and large non-EGU boilers and turbines.

[57] The term ''such sources'' in § 51.121(f)(2)(ii) refers to the large EGUs and large non-EGU boilers and turbines identified in § 51.121(f)(2).

large EGUs and large non-EGU boilers and turbines pursuant to § 51.121(g)(2)(iii) and used in the demonstrations required under § 51.121(g)(1). The fact that the phrase in § 51.121(f)(2)(ii) refers to the second type of emissions amount is evident for two reasons: first, the relevant amounts are projected ''by the State'' and not by EPA, and second, the purpose of § 51.121(f)(2)(ii) is to require enforceable mechanisms to ensure achievement of post-control emissions levels rather than pre-control emissions levels. Thus, the commenter's objection to the removal of the baseline emissions inventory table in § 51.121(g)(2)(ii) is misplaced.

D. Post-NBTP Transition Requirements

Comment: Without expressing any objection to the proposed clarifying amendments to the post-NBTP transition provision at § 51.121(r)(2), one commenter requested confirmation that EPA does not intend the requirements of the provision as revised to apply with regard to EGUs that participate in the CSAPR Update trading program under the regulations set forth at 40 CFR part 97, subpart EEEEE,[58] pursuant to an approved SIP revision.

Response: The proposed clarifying revisions to the NO_X SIP Call post-NBTP transition provision at § 51.121(r)(2) add a cross-reference to 40 CFR 52.38(b)(10)(ii), which is an existing provision of the CSAPR regulations governing SIP approvals. Under this provision of the CSAPR regulations, where a state has an approved full CSAPR SIP revision requiring certain units in the state to participate in a state seasonal NO_X trading program integrated with the Federal CSAPR Update seasonal NO_X trading program established under 40 CFR part 97, subpart EEEEE, the NO_X SIP Call's post-NBTP transition requirements under § 51.121(r)(2) are satisfied with regard to any of the state's large EGUs or large non-EGU boilers and turbines participating in that state trading program. As explained in the proposal,[59] the addition of the cross reference in § 51.121(r)(2) is not a substantive change because the approval of a full CSAPR SIP would produce this result even without a cross-reference, but the cross-reference clarifies the NO_X SIP Call regulations.

Comment: Without expressing any objection to the proposed clarifying amendments to the post-NBTP transition provision at § 51.121(r)(2), one commenter requested that EPA further clarify the Rule's post-NBTP transition requirements by adding a new regulatory provision indicating that where a state does not require its large non-EGU boilers and turbines to participate in the CSAPR Update trading program, the state must impose a cap on these units' collective seasonal NO_X mass emissions equivalent to the portion of the statewide emissions budget assigned to the units under the NBTP. The commenter requested that EPA add the new provision to § 51.121(f)(2), the provision establishing the requirement for enforceable limits on seasonal NO_X mass emissions from large EGUs and large non-EGU boilers and turbines.

Response: This comment is outside the scope of the proposal. A requirement for a cap on the collective NO_X mass emissions of each state's large non-EGU boilers and turbines does not appear in the existing regulatory text at § 51.121 because, as discussed in the proposal and summarized in section II.A. of this document, the NO_X SIP Call did not require states to control any specific types of sources or to adopt any specific types of control measures. Even where states chose to adopt control measures for large EGUs and large non-EGU boilers and turbines, thereby triggering requirements for enforceable limits on seasonal NO_X mass emissions from those sources, the regulations provided several permissible alternative forms for such limits.[60] Similarly, the post-NBTP provision at § 51.121(r)(2) does not prescribe what types of sources states must control to satisfy the post-NBTP transition requirements or what types of control measures states must employ, but simply requires each state with units affected under the NO_X SIP Call that do not participate in a successor trading program to the NBTP to ''revise the SIP to adopt control measures that satisfy the same portion of the State's emission reduction requirements under [§ 51.121] as the State projected [the NBTP] would satisfy.'' The commenter's requested amendment would codify as a Federal requirement what may be the simplest way to satisfy the Rule's post-NBTP transition requirements, but it would also reduce states' flexibility by eliminating options to satisfy the post-NBTP transition requirements in other ways, and the reduction in flexibility would represent a substantive change to the existing regulations. EPA did not propose substantive changes to the post-NBTP transition provision and made clear that the only provision of the NO_X SIP Call regulations being reopened for substantive comment was the provision concerning part 75 monitoring requirements for large EGUs and large non-EGU boilers and turbines.

Comment: Without expressing any objection to the proposed clarifying amendments to the post-NBTP transition provision at § 51.121(r)(2), two commenters requested that EPA identify in the regulations the portion of each state's statewide emissions budget assigned to the state's large non-EGU boilers and turbines by adding this information either as a new table or as an additional column in the table of statewide budgets in § 51.121(e)(2)(i). The commenters suggested that inclusion of these amounts in the regulations could help states address their post-NBTP transition requirements. One of the commenters accompanied this comment with a request that EPA confirm ''it is the EPA's intent that all required SIP elements for the NO_X SIP Call are contained under § 51.121.''

Response: These comments are outside the scope of the proposal. The portions of the statewide emissions budgets assigned to various categories of sources do not appear in the existing regulatory text at § 51.121 because, as discussed in the proposal and summarized in section II.A. of this document, the NO_X SIP Call did not establish required post-control emissions amounts for any specific categories of sources. Instead, each state determined what portions of its post-control statewide emissions budget to assign to the specific categories of sources in the state, and the assignments were approved in separate SIP approval actions for each state.[61] Adopting the state-determined, sector-specific assignments as Federal requirements at this time would be a substantive change to the existing regulations because it would reduce states' flexibility to revise their previous choices and select other ways of addressing their post-NBTP transition requirements. EPA did not propose substantive changes to the post-NBTP transition provision and made clear that the only provision of the NO_X SIP Call regulations being reopened for

[58] The commenter similarly requests confirmation with regard to EGUs that participate in the original CSAPR seasonal NO_X trading program under the regulations set forth at 40 CFR part 97, subpart BBBBB, but this request is moot because there are no states subject to the NO_X SIP Call with EGUs that continue to participate in the original CSAPR seasonal NO_X trading program.

[59] 83 FR at 48760–61.

[60] *See* 40 CFR 51.121(f)(2)(i)(A)–(C).

[61] *See, e.g.,* 67 FR 68542 (Nov. 12, 2002) (proposing to approve Virginia SIP provisions assigning portions of the statewide emissions budget to large EGUs and large non-EGU boilers and turbines); *see also* 68 FR 40520 (July 8, 2003) (finalizing approval).

substantive comment was the provision concerning part 75 monitoring requirements for large EGUs and large non-EGU boilers and turbines.

Comment: Without expressing any objection to the proposed clarifying revisions to the post-NBTP transition provision at § 51.121(r)(2), one commenter noted the proposed insertion of the words ''or included'' into the phrase ''a State whose SIP . . . includes *or included* an emission trading program approved under [§ 51.121]'' and indicated that the commenter's interpretation of the revised language is that ''no action is necessary to affirm [the commenter's] obligation to maintain NO_X SIP Call emissions control.'' The commenter requested that EPA clarify in this final action if the state's interpretation is not correct.

Response: EPA considers this comment to be outside the scope of the proposal. As discussed in the proposal, the reason for inserting the words ''or included'' in § 51.121(r)(2) was to eliminate any possible mistaken inference that a state's obligation to maintain NO_X SIP Call emission controls might be contingent on whether its SIP currently includes trading program provisions and to reinforce that the Rule's emissions reductions are permanent and enforceable.[62] EPA does not consider this to be a substantive change to the regulations.[63] While the commenter contends that its request for clarification about the need for any further action regarding its SIP arises from the proposed insertion, the commenter has not explained how, if at all, its interpretation of the post-NBTP transition requirements might have been influenced by the proposed insertion, and there is no indication that the commenter's interpretation has changed from its interpretation before issuance of the proposal.[64] Given the lack of any apparent connection between the proposed revision and the commenter's request for clarification, EPA interprets the comment as a request for a determination concerning the commenter's SIP that is outside the scope of the proposal. For this action, EPA did not propose to make any determinations regarding whether any further action is or is not necessary to address any specific state's post-NBTP transition requirements. Accordingly, EPA is not making any such state-specific determinations in this final action, either through express statements or otherwise.

IV. Final Action

For the reasons discussed in the proposal, as supplemented by the discussion in this document, EPA is finalizing amendments to the NO_X SIP Call regulations at 40 CFR 51.121 and 51.122 and amendments to associated cross-references in the CSAPR regulations at 40 CFR 52.38. In place of the current requirement for states to include provisions in their SIPs under which certain emissions sources must monitor their seasonal NO_X mass emissions according to 40 CFR part 75, the amended regulations will allow states to include alternate forms of monitoring requirements in their SIPs for NO_X SIP Call purposes. Other amendments remove obsolete provisions and clarify the remaining regulations but do not substantively alter any current regulatory requirements.

Descriptions of the individual proposed amendments are provided in sections II.B. and II.C. of this document and further discussion is provided in the proposal. EPA is finalizing the amendments generally as proposed with the following further revisions, all of which EPA considers to be non-substantive changes from the proposal:

- To improve clarity, the final regulatory text of § 51.121(i)(4) is being revised from the proposed amended text in two ways. First, the final revisions indicate that where a state chooses to require part 75 monitoring for some or all large EGUs and large non-EGU boilers and turbines for NO_X SIP Call purposes, the ''full set of'' monitoring, recordkeeping, and reporting provisions in subpart H of part 75 must be required. The added words clarify that the amendments do not authorize states to create partial versions of the part 75 regulations that EPA would then have to administer on a state-specific basis. Second, the final revisions remove a phrase indicating that the amended text does not create any exception to any part 75 requirements that may apply to a source under another legal authority. The removed phrase is unnecessary because, on its face, the amended text merely gives states an option to require part 75 monitoring for NO_X SIP Call purposes and does not create or authorize any exceptions to any requirements that may apply to any source under any legal authority. EPA believes the text of the final amendment is clearer and does not differ substantively from the text of the amendment as proposed.
- As discussed in EPA's response to comments in section III.B. of this document, the regulatory text expressing the NO_X SIP Call's emissions reduction requirements is being further clarified by using more precise terminology and documenting the definitions that already apply for two important terms. The final revisions (1) use the standard term ''NO_X ozone season budget'' consistently, (2) specify emissions ''during the ozone season'' where appropriate, (3) indicate the respective years of applicability for the Phase I and final emissions budgets, and (4) add definitions of the terms ''nitrogen oxides or NO_X'' and ''ozone season'' to § 51.121. The term ''nitrogen oxides or NO_X'' is defined as ''all oxides of nitrogen except nitrous oxide (N_2O), reported on an equivalent molecular weight basis as nitrogen dioxide (NO_2).'' The term ''ozone season'' is defined as ''the period from May 1 through September 30 of a year.'' The added definitions do not alter any regulatory requirements because they are substantively identical to the definitions that already explicitly apply for purposes of § 51.122 and that have historically been used in practice for purposes of § 51.121 as well.[65] The additional revisions affect the regulatory text at § 51.121(a)(3), (b)(1)(i) and (iii), (e)(1), (e)(2)(i) and (ii), (f) introductory

[62] 83 FR at 48760–61.

[63] EPA notes that the continued applicability of the post-NBTP transition requirements following the replacement of the CAIR seasonal NO_X trading program by the original CSAPR seasonal NO_X trading program was discussed in the preamble for the CSAPR final rule. 76 FR at 48325.

[64] Like several other states, when the NBTP was discontinued, the commenter elected to include its large non-EGU boilers and turbines in the replacement seasonal NO_X trading program established under CAIR, and EPA subsequently approved the removal of the NBTP from its SIP. The commenter is thus a state whose SIP ''included'' a trading program approved under § 51.121. The commenter clearly is not contending that, prior to this action, it believed the requirement to adopt control measures replacing the NBTP no longer applied to it because its SIP no longer ''includes'' the NBTP and that, now, the insertion of the words ''or included'' would cause it to understand the requirement once again applies, although such a contention would have internal logic and would be consistent with the purpose of the proposed clarification. The comment does not set forth the commenter's interpretation of § 51.121(r)(2) prior to this action, but if the commenter is contending that, prior to this action, it understood the requirement to adopt replacement control measures applied to it and that, now, the insertion of the words ''or included'' would cause it to believe the requirement no longer applies, that contention would be illogical. If the commenter is contending that the insertion of the words ''or included'' would alter its interpretation concerning the nature of the replacement control measures that can satisfy the post-NBTP transition requirements, that contention would also be illogical because with or without the added words, the post-NBTP transition provision does not address the nature of replacement control measures that states may or must adopt.

[65] *See* 40 CFR 51.122(a); *see also id.* § 51.50 (definition of ''nitrogen oxides'').

text, (f)(2) introductory text, (f)(2)(i)(C), (g)(1), (g)(2)(i) and (iii), (i), and (j)(1).

- Instead of being removed as proposed, the provision at § 51.121(d)(2) concerning procedural requirements for SIP submissions is being revised to incorporate the updated procedural requirements for SIP submissions at 40 CFR 51.103. In the proposal,[66] EPA stated the intent for the completeness and format requirements in § 51.103 to apply to any future SIP submissions under § 51.121. The final revision makes such applicability explicit and is consistent with several other provisions of § 51.121 that similarly incorporate requirements set forth in other sections of 40 CFR part 51.
- An additional editorial revision is being made to the text of § 51.121(k)(2). The revision clarifies the regulations by standardizing citation formats.

A redline-strikeout document showing the text of 40 CFR 51.121 and 51.122 with the amendments adopted in this action, including all the proposed amendments to the NO_X SIP Call regulations with the further revisions just described, is available in the docket for this action.

The amendments finalized in this action are effective immediately upon publication of the action in the **Federal Register**. This final action is not subject to requirements specifying a minimum period between publication and effectiveness under either Congressional Review Act (CRA) section 801(a)(3), 5 U.S.C. 801(a)(3), or Administrative Procedure Act (APA) section 553(d), 5 U.S.C. 553(d).

CRA section 801(a)(3) generally prohibits a ''major rule'' from taking effect earlier than 60 days after the rule is published in the **Federal Register**. Generally, under CRA section 804(2), 5 U.S.C. 804(2), a major rule is a rule that the Office of Management and Budget (OMB) finds has resulted in or is likely to result in (1) an annual effect on the economy of $100 million or more, (2) major cost or price increases, or (3) other significant adverse economic effects. This action is not a major rule for CRA purposes.

As discussed in section VI.M. of this document, EPA is issuing the amendments under CAA section 307(d). This provision does not include requirements governing the effective date of a rule promulgated under it and, accordingly, EPA has discretion in establishing the effective date. While APA section 553(d) generally provides that rules may not take effect earlier than 30 days after they are published in the **Federal Register**, CAA section 307(d)(1) clarifies that ''[t]he provisions of [APA] section 553 . . . shall not, except as expressly provided in this section, apply to actions to which this subsection applies.'' Thus, APA section 553(d) does not apply to the amendments. Nevertheless, in making this final action effective immediately upon publication, EPA has considered the purposes underlying APA section 553(d). The primary purpose of the prescribed 30-day waiting period is to give affected parties a reasonable time to adjust their behavior and prepare before a final rule takes effect. The amendments made in this action do not impose any new regulatory requirements and therefore do not necessitate time for affected sources to adjust their behavior or otherwise prepare for implementation. Further, APA section 553(d) expressly allows an effective date earlier than 30 days after publication for a rule that ''grants or recognizes an exemption or relieves a restriction.'' This action relieves an existing restriction and allows EPA to approve SIPs with more flexible monitoring requirements, which in turn could lead to reduced monitoring costs for certain sources. Consequently, making the amendments effective immediately upon publication of the action is consistent with the purposes of APA section 553(d).

V. Impacts of the Amendments

The only amendment being finalized in this action that substantively alters existing regulatory requirements is the amendment allowing states to revise their SIPs, for NO_X SIP Call purposes only, to establish monitoring requirements other than part 75 monitoring requirements. The amendments do not change any of the Rule's existing regulatory requirements related to statewide emissions budgets or enforceable mass emissions limits for large EGUs and large non-EGU boilers and turbines. Accordingly, EPA expects that the amendments will have no impact on emissions or air quality. However, EPA does expect that the amendment to the Rule's monitoring requirements will ultimately allow some sources to reduce their monitoring costs because of alternate monitoring requirements established in SIP revisions submitted and approved for their states. Because states, not EPA, will decide whether to revise the monitoring requirements in their SIPs and because EPA lacks complete information on the remaining monitoring requirements that the sources would face, there is considerable uncertainty concerning the amount of monitoring cost reductions that may be facilitated by this action, and EPA did not present a quantitative estimate of potential monitoring cost reductions in the proposal. For purposes of the final action, based in part on improved information obtained through comments, EPA has estimated a range of potential annual monitoring cost reductions from $1.2 million to $3.3 million, with a midpoint estimate of $2.25 million, as further discussed below. Given the absence of any change in emissions or air quality, there would be no change in the public health and environmental benefits attributable to the NO_X SIP Call's emissions reduction requirements, and the likely reductions in monitoring costs therefore are expected to constitute positive net benefits from this action.

As of December 2018, EPA's records indicate that there are approximately 315 existing large EGUs and large non-EGU boilers and turbines in the NO_X SIP Call region that could potentially be affected by the monitoring amendment if all states were to revise their SIPs.[67] To estimate how many of these potentially affected existing units may ultimately face alternate monitoring requirements made possible by the monitoring amendment in this action, EPA is relying on information obtained from states' comments. Six states submitted comments expressing support for the proposed monitoring amendment.[68] While these comments do not in any way obligate the states to submit SIP revisions with alternate monitoring requirements, and additional states that did not submit comments could also choose to submit SIP revisions, EPA believes that the comments provide a reasonable basis for assuming, solely for purposes of developing an estimate of this action's impacts, that the 102 existing units in these six states will ultimately face alternate monitoring requirements of some kind.[69] According to the monitoring plans for these units, 34 units use both gas concentration CEMS

[66] 83 FR at 48761.

[67] The spreadsheet referenced in note 54 *supra* identifies 317 potentially affected existing units. As noted in section II.B. of this document, in the proposal for this action EPA indicated that there were approximately 310 potentially affected existing units. Several additional units started reporting emissions for NO_X SIP Call purposes in 2018.

[68] The six states are Indiana, Michigan, North Carolina, Ohio, South Carolina, and West Virginia.

[69] The 102 units are the existing units identified in the spreadsheet referenced in note 54 *supra* for these six states. While any new units in these states that otherwise would have been required to use CEMS methodologies for NO_X SIP Call purposes could also experience monitoring cost reductions, EPA believes it is reasonable to ignore possible new units in preparing this estimate due to the larger numbers of existing units.

and stack gas flow rate CEMS, 35 units use gas concentration CEMS but not stack gas flow rate CEMS, and 33 units use non-CEMS methodologies. For purposes of estimating potential monitoring cost reductions, EPA has focused on the units currently using CEMS because, as noted in the proposal and in section II.B. of this document, EPA expects that units already using non-CEMS methodologies under part 75 would experience little or no reduction in monitoring costs from alternate monitoring requirements.

To represent the alternate monitoring requirements that the units currently using CEMS could face in a manner that reflects the substantial uncertainty on this issue, EPA has used a range of assumptions. Specifically, to estimate the low end of the range, EPA has assumed that the only change from current requirements is that the 34 units currently using both gas concentration CEMS and stack gas flow rate CEMS will discontinue the use of stack gas flow rate CEMS. EPA considers this assumption to be reasonable for purposes of estimating potential monitoring cost reductions because requirements to use stack gas flow rate CEMS are relatively uncommon in non-part 75 monitoring regulations. EPA also believes the units currently using stack gas flow rate CEMS are more likely than other potentially affected units to continue to be subject to requirements to use gas concentration CEMS because many of these units combust solid fuel and consequently may have triggered emission control requirements and associated emissions monitoring requirements under other regulations. To estimate the high end of the range, EPA has assumed that in addition to the change just described, the 35 units currently using only gas concentration CEMS will switch to a non-CEMS methodology. While it is possible that some of these units may also face continued requirements to use gas concentration CEMS under other regulations, EPA believes the likelihood that these units, none of which combust solid fuel, would be eligible to use non-CEMS methodologies is greater than for the units that currently use both gas concentration CEMS and stack gas flow rate CEMS.

To estimate the monitoring cost reductions associated with the assumed range of changes in monitoring requirements, EPA has used the cost estimates for the various part 75 monitoring methodologies contained in the information collection request (ICR) renewal prepared in conjunction with this action for purposes of the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.*[70] Based on the cost estimates in the ICR renewal, EPA has estimated that the potential annual cost reduction from discontinuing the use of stack gas flow rate CEMS—including reductions in labor costs, non-labor operating and maintenance costs (including contractor costs), and annualized capital costs—is approximately $35,000 per unit, while the analogous potential annual cost reduction from discontinuing the use of gas concentration CEMS is approximately $60,000 per unit.[71] Multiplying these per-unit amounts by the respective numbers of units yields an estimated range of potential annual monitoring cost reductions from $1.2 million to $3.3 million.[72] The midpoint of this range is a potential reduction in annual monitoring costs of $2.25 million.

VI. Statutory and Executive Order Reviews

Additional information about these statutes and executive orders can be found at *https://www.epa.gov/laws-regulations/laws-and-executive-orders*.

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

This action is not a significant regulatory action and was therefore not submitted to OMB for review.

B. Executive Order 13771: Reducing Regulations and Controlling Regulatory Costs

This action is considered an Executive Order 13771 deregulatory action. This final rule provides meaningful burden reduction by allowing states to establish lower-cost monitoring requirements in their SIPs for some sources as alternatives to part 75 monitoring requirements. Because states, not EPA, will decide whether to revise the monitoring requirements in their SIPs and because EPA lacks complete information on the remaining monitoring requirements that the sources would face, there is considerable uncertainty regarding the amount of monitoring cost reductions that may occur, but EPA has quantified an estimated range in section V of this document. In addition, the proposal's qualitative discussion of the potential monitoring cost reductions[73] is summarized in section II.B. of this document.

C. Paperwork Reduction Act

This action does not impose any new information collection burden under the Paperwork Reduction Act. OMB has previously approved the information collection activities contained in the existing regulations and has assigned OMB control number 2060–0445. However, to reflect the amendment allowing states to establish potentially lower-cost monitoring requirements for some sources as alternatives to the current part 75 monitoring requirements, EPA submitted an information collection request (ICR) renewal to OMB in conjunction with the proposal for this action. The ICR document prepared by EPA, which has been assigned EPA ICR number 1857.08, can be found in the docket for this action. None of the comments that EPA received during the public comment period for the proposal addressed the ICR renewal.

Like the current ICR, the ICR renewal reflects the information collection burden and costs associated with part 75 monitoring requirements for sources that are subject to part 75 monitoring requirements under the SIP revisions addressing states' NO_X SIP Call obligations and that are not subject to part 75 monitoring requirements under the Acid Rain Program or a CSAPR trading program. The ICR renewal is generally unchanged from the current ICR except that the renewal reflects projected decreases in the numbers of sources that would perform part 75 monitoring for NO_X SIP Call purposes based on an assumption (made only for purposes of estimating information collection burden and costs for the ICR renewal) that, over the course of the 3-year renewal period, some states will revise their SIPs to replace part 75 monitoring requirements for some sources with lower-cost monitoring requirements. As under the current ICR, all information collected from sources under the ICR renewal will be treated as public information.

Respondents/affected entities: Fossil fuel-fired boilers and stationary combustion turbines that have heat input capacities greater than 250 mmBtu/hr or serve electricity generators

[70] *See* section VI.C. *infra.*

[71] *See* Information Collection Request Renewal for the NO_X SIP Call: Supporting Statement (September 2018) at 12 (Table 6–2), available in the docket for this action. The $35,000 estimate is the rounded difference between the sum of the amounts in the labor, O&M, and annualized capital cost columns on line 6(a) and the sum of the amounts in the same columns on line 6(b). The $60,000 estimate is the rounded difference from the same calculation performed using the amounts on lines 6(b) and 6(c) instead.

[72] Calculation of low end of range: 34 units × $35,000 per unit = $1.2 million.

Calculation of high end of range: 35 units × $60,000 per unit + $1.2 million = $3.3 million.

[73] 83 FR at 48761–62.

with nameplate capacities greater than 25 MW and that are not subject to part 75 monitoring requirements under another program.

Respondents' obligation to respond: Mandatory if elected by the state (40 CFR 51.121(i)(4) as amended).

Estimated number of respondents: 340 (average over 2019–2021 renewal period).

Frequency of response: Quarterly, occasionally.

Total estimated burden: 131,945 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: $19,143,004 (per year), includes $8,256,087 annualized capital or operation & maintenance costs.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR part 9. When OMB approves this ICR renewal, the Agency will announce that approval in the **Federal Register**.

D. Regulatory Flexibility Act

I certify that this action will not have a significant economic impact on a substantial number of small entities under the Regulatory Flexibility Act, 5 U.S.C. 601–612. In making this determination, the impact of concern is any significant adverse economic impact on small entities. An agency may certify that a rule will not have a significant economic impact on a substantial number of small entities if the rule relieves regulatory burden, has no net burden, or otherwise has a positive economic effect on the small entities subject to the rule. This action does not directly regulate any entity, but simply allows states to establish potentially lower-cost monitoring requirements for some sources and generally streamlines existing regulations. EPA has therefore concluded that this action will either relieve or have no net regulatory burden for all affected small entities.

E. Unfunded Mandates Reform Act

This action does not contain any unfunded mandate as described in the Unfunded Mandates Reform Act, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. The action imposes no enforceable duty on any state, local, or tribal governments or the private sector. This action simply allows states to establish potentially lower-cost monitoring requirements for some sources and generally streamlines existing regulations.

F. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government. This action simply allows states to establish potentially lower-cost monitoring requirements for some sources and generally streamlines existing regulations.

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

This action does not have tribal implications as specified in Executive Order 13175. It will not have substantial direct effects on tribal governments, on the relationship between the Federal Government and Indian tribes, or on the distribution of power and responsibilities between the Federal Government and Indian tribes. This action simply allows states to establish potentially lower-cost monitoring requirements for some sources and generally streamlines existing regulations. Thus, Executive Order 13175 does not apply to this action.

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

EPA interprets Executive Order 13045 as applying only to those regulatory actions that concern environmental health or safety risks that EPA has reason to believe may disproportionately affect children, per the definition of ''covered regulatory action'' in section 2–202 of the Executive Order. This action is not subject to Executive Order 13045 because it does not concern an environmental health risk or safety risk. This action simply allows states to establish potentially lower-cost monitoring requirements for some sources and generally streamlines existing regulations.

I. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use

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

J. National Technology Transfer Advancement Act

This rulemaking does not involve technical standards.

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

EPA believes that this action is not subject to Executive Order 12898 because it does not establish an environmental health or safety standard. This action simply allows states to establish potentially lower-cost monitoring requirements for some sources and generally streamlines existing regulations. Consistent with Executive Order 12898 and EPA's environmental justice policies, EPA considered effects on low-income populations, minority populations, and indigenous peoples while developing the original NO_X SIP Call. The process and results of that consideration are described in the Regulatory Impact Analysis for the NO_X SIP Call.

L. Congressional Review Act

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

M. Determinations Under CAA Section 307(b) and (d)

CAA section 307(b)(1), 42 U.S.C. 7607(b)(1), indicates which United States Courts of Appeals have venue for petitions of review of final actions by EPA. This section provides, in part, that petitions for review must be filed in the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) if (i) the Agency action consists of ''nationally applicable regulations promulgated, or final action taken, by the Administrator,'' or (ii) the action is locally or regionally applicable, but ''such action is based on a determination of nationwide scope or effect and if in taking such action the Administrator finds and publishes that such action is based on such a determination.'' This action amends existing regulations that apply to 20 states and the District of Columbia, and thus the action applies to the same 21 jurisdictions. The existing regulations were promulgated to address interstate transport of air pollution across the eastern half of the nation and the resulting emissions reductions have been relied on as a basis for actions redesignating areas in at least 20 states to attainment with one or more NAAQS.

The states affected under the regulations and relying on the resulting emissions reductions are located in multiple EPA Regions and Federal judicial circuits. Previous final actions promulgating and amending the existing regulations were nationally applicable and reviewed in the D.C. Circuit. For these reasons, the Administrator determines that this final action is nationally applicable or, in the alternative, is based on a determination of nationwide scope and effect for purposes of section 307(b)(1). Thus, pursuant to section 307(b), any petitions for review of this final action must be filed in the D.C. Circuit within 60 days from the date this final action is published in the **Federal Register**.

CAA section 307(d), 42 U.S.C. 7607(d), contains rulemaking and judicial review provisions that apply to certain EPA actions under the CAA including, under section 307(d)(1)(V), ''such other actions as the Administrator may determine.'' In accordance with section 307(d)(1)(V), the Administrator determines that the provisions of section 307(d) apply to this final action. EPA has complied with the procedural requirements of section 307(d) during the course of this rulemaking.

List of Subjects

40 CFR Part 51

Environmental protection, Administrative practice and procedure, Air pollution control, Incorporation by reference, Intergovernmental relations, Nitrogen oxides, Ozone, Particulate matter, Reporting and recordkeeping requirements, Sulfur dioxide.

40 CFR Part 52

Environmental protection, Administrative practice and procedure, Air pollution control, Incorporation by reference, Intergovernmental relations, Nitrogen oxides, Ozone, Particulate matter, Reporting and recordkeeping requirements, Sulfur dioxide.

Dated: February 26, 2019.

Andrew R. Wheeler,

Acting Administrator.

For the reasons stated in the preamble, parts 51 and 52 of chapter I of title 40 of the *Code of Federal Regulations* are amended as follows:

PART 51—REQUIREMENTS FOR PREPARATION, ADOPTION, AND SUBMITTAL OF IMPLEMENTATION PLANS

■ 1. The authority citation for part 51 continues to read as follows:

Authority: 23 U.S.C. 101; 42 U.S.C. 7401–7671q.

Subpart G—Control Strategy

§ 51.121 [Amended]

■ 2. Section 51.121 is amended by:
■ a. Revising the section heading;
■ b. Removing and reserving paragraph (a)(2);
■ c. Revising paragraph (a)(3);
■ d. In paragraph (b)(1) introductory text, removing the text ''section, the'' and adding in its place the text ''section, each'';
■ e. In paragraph (b)(1)(i), adding the words ''during the ozone season'' after the words ''NO_X emissions'', adding the words ''applicable NO_X ozone season'' before the word ''budget'', and removing the text ''(except as provided in paragraph (b)(2) of this section),'' and adding in its place a semicolon;
■ f. In paragraph (b)(1)(ii), removing the period and adding in its place ''; and'';
■ g. In paragraph (b)(1)(iii), adding the words ''NO_X ozone season'' before the word ''budget'';
■ h. Removing and reserving paragraph (b)(2);
■ i. In paragraph (c)(1), removing the text ''With respect to the 1-hour ozone NAAQS:'';
■ j. In paragraph (c)(2), removing the text ''With respect to the 1-hour ozone NAAQS, the portions of Missouri, Michigan, and Alabama'' and adding in its place the text ''The portions of Alabama, Michigan, and Missouri'';
■ k. Removing and reserving paragraph (d)(1);
■ l. Revising paragraph (d)(2);
■ m. In paragraph (e)(1), adding the words ''ozone season'' before the word ''budget'';
■ n. Revising paragraph (e)(2)(i);
■ o. In paragraph (e)(2)(ii)(A), adding the words ''ozone season'' before the word ''budget'';
■ p. In paragraph (e)(2)(ii)(B), removing the text ''De Kalb'' and adding in its place the text ''DeKalb'';
■ q. In paragraph (e)(2)(ii)(E), removing the text ''St. Genevieve,'' and after the text ''St. Louis City,'' adding the text ''Ste. Genevieve,'';
■ r. Removing paragraphs (e)(3), (4), and (5);
■ s. In paragraphs (f) introductory text and (f)(2) introductory text, adding the words ''ozone season'' before the word ''budget'';
■ t. In paragraph (f)(2)(i)(B), removing the words ''mass NO_X'' and adding in their place the words ''NO_X mass'';
■ u. In paragraph (f)(2)(i)(C), removing ''paragraphs (f)(2)(i)(A) or (f)(2)(i)(B)'' and adding in its place ''paragraph (f)(2)(i)(A) or (B)'' and adding the words ''ozone season'' before the word ''budget'';
■ v. In paragraph (f)(2)(ii), removing the text ''(b)(1) (i)'' and adding in its place the text ''(b)(1)(i)'';
■ w. In paragraph (g)(1), adding the words ''ozone season'' before the word ''budget'';
■ x. In paragraph (g)(2)(i), adding the words ''during the ozone season'' after the words ''mass emissions'', adding the words ''ozone season'' before the word ''budget'', and removing the text ''as set forth for the State in paragraph (g)(2)(ii) of this section,'';
■ y. Removing and reserving paragraph (g)(2)(ii);
■ z. In paragraph (g)(2)(iii), adding the words ''during the ozone season'' after the words ''mass emissions'';
■ aa. In paragraph (h), removing the words ''of this part'';
■ bb. In paragraph (i) introductory text, adding the words ''ozone season'' before the word ''budget'';
■ cc. In paragraphs (i)(2) and (3), removing the words ''of this part'';
■ dd. Revising paragraphs (i)(4) and (5);
■ ee. In paragraph (j)(1), adding the words ''ozone season'' before the word ''budget'';
■ ff. In paragraph (k)(2), removing the text ''CAA'' and adding in its place the text ''CAA, 42 U.S.C. 7414'';
■ gg. In paragraphs (l) and (m), removing the phrase ''of this part'' everywhere it appears;
■ hh. In paragraph (n), removing the text ''§ 52.31(c) of this part'' and adding in its place the text ''40 CFR 52.31(c)'' and removing the text ''§ 52.31 of this part'' and adding in its place the text ''40 CFR 52.31'';
■ ii. In paragraph (o), removing the words ''of this part'';
■ jj. Removing and reserving paragraphs (p) and (q); and
■ kk. Revising paragraph (r).

The revisions read as follows:

§ 51.121 Findings and requirements for submission of State implementation plan revisions relating to emissions of nitrogen oxides.

(a) * * *

(3) As used in this section, these terms shall have the following meanings:

Nitrogen oxides or *NO_X* means all oxides of nitrogen except nitrous oxide (N_2O), reported on an equivalent molecular weight basis as nitrogen dioxide (NO_2).

Ozone season means the period from May 1 to September 30 of a year.

Phase I SIP submission means a SIP revision submitted by a State on or before October 30, 2000 in compliance with paragraph (b)(1)(ii) of this section to limit projected NO_X emissions during the ozone season from sources in the relevant portion or all of the State, as applicable, to no more than the State's Phase I NO_X ozone season budget under paragraph (e) of this section.

Phase II SIP submission means a SIP revision submitted by a State in compliance with paragraph (b)(1)(ii) of this section to limit projected NO_X emissions during the ozone season from sources in the relevant portion or all of the State, as applicable, to no more than the State's final NO_X ozone season budget under paragraph (e) of this section.

* * * * *

(d) * * *

(2) Each SIP submission under this section must comply with § 51.103 (regarding submission of plans).

(e) * * *

(2)(i) The State-by-State amounts of the Phase I and final NO_X ozone season budgets, expressed in tons, are listed in Table 1 to this paragraph (e)(2)(i):

TABLE 1 TO PARAGRAPH (e)(2)(i)—STATE NO_X OZONE SEASON BUDGETS

State	Phase I NO_X ozone season budget (2004–2006)	Final NO_X ozone season budget (2007 and thereafter)
Alabama	124,795	119,827
Connecticut	42,891	42,850
Delaware	23,522	22,862
District of Columbia	6,658	6,657
Illinois	278,146	271,091
Indiana	234,625	230,381
Kentucky	165,075	162,519
Maryland	82,727	81,947
Massachusetts	85,871	84,848
Michigan	191,941	190,908
Missouri	....	61,406
New Jersey	95,882	96,876
New York	241,981	240,322
North Carolina	171,332	165,306
Ohio	252,282	249,541
Pennsylvania	268,158	257,928
Rhode Island	9,570	9,378
South Carolina	127,756	123,496
Tennessee	201,163	198,286
Virginia	186,689	180,521
West Virginia	85,045	83,921

* * * * *

(i) * * *

(4) If the revision contains measures to control fossil fuel-fired NO_X sources serving electric generators with a nameplate capacity greater than 25 MWe or boilers, combustion turbines or combined cycle units with a maximum design heat input greater than 250 mmBtu/hr, then the revision may require some or all such sources to comply with the full set of monitoring, recordkeeping, and reporting provisions of 40 CFR part 75, subpart H. A State requiring such compliance authorizes the Administrator to assist the State in implementing the revision by carrying out the functions of the Administrator under such part.

(5) For purposes of paragraph (i)(4) of this section, the term ''fossil fuel-fired'' has the meaning set forth in paragraph (f)(3) of this section.

* * * * *

(r)(1) Notwithstanding any provisions of subparts A through I of 40 CFR part 96 and any State's SIP to the contrary, with regard to any ozone season that occurs after September 30, 2008, the Administrator will not carry out any of the functions set forth for the Administrator in subparts A through I of 40 CFR part 96 or in any emissions trading program provisions in a State's SIP approved under this section.

(2) Except as provided in 40 CFR 52.38(b)(10)(ii), a State whose SIP is approved as meeting the requirements of this section and that includes or included an emissions trading program approved under this section must revise the SIP to adopt control measures that satisfy the same portion of the State's NO_X emissions reduction requirements under this section as the State projected such emissions trading program would satisfy.

§ 51.122 [Amended]

■ 3. Section 51.122 is amended by:

■ a. In paragraph (c)(1)(ii), removing the text ''pursuant to a trading program approved under § 51.121(p) or'';

■ b. In paragraph (e), removing the first sentence;

■ c. In paragraph (f), removing the paragraph heading; and

■ d. Removing the second paragraph (g).

PART 52—APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS

■ 4. The authority citation for part 52 continues to read as follows:

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

Subpart A—General Provisions

§ 52.38 [Amended]

■ 5. In § 52.38, paragraphs (b)(8)(ii), (b)(8)(iii)(A)(*2*), (b)(9)(ii), and (b)(9)(iii)(A)(*2*) are amended by removing the text ''§ 51.121(p)'' and adding in its place the text ''§ 51.121''.

[FR Doc. 2019–03854 Filed 3–7–19; 8:45 am]

BILLING CODE 6560–50–P

FEDERAL COMMUNICATIONS COMMISSION

47 CFR Part 27

[WT Docket No. 06–150; DA 19–77]

Service Rules for the 698–746, 747–762, and 777–792 Bands

AGENCY: Federal Communications Commission.

ACTION: Final rule.

SUMMARY: In this document, the Federal Communications Commission (Commission) describes the process for relicensing 700 MHz spectrum that is returned to the Commission's inventory

ELECTRONIC CODE OF FEDERAL REGULATIONS

e-CFR data is current as of April 8, 2019

Title 40: Protection of Environment
PART 75—CONTINUOUS EMISSION MONITORING

Subpart H—NO_X Mass Emissions Provisions

Contents

SOURCE: 63 FR 57507, Oct. 27, 1998, unless otherwise noted.

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§75.70 NO_X mass emissions provisions.

(a) *Applicability.* The owner or operator of a unit shall comply with the requirements of this subpart to the extent that compliance is required by an applicable State or federal NO_X mass emission reduction program that incorporates by reference, or otherwise adopts the provisions of, this subpart.

(1) For purposes of this subpart, the term "affected unit" shall mean any unit that is subject to a State or federal NO_X mass emission reduction program requiring compliance with this subpart, the term "non-affected unit" shall mean any unit that is not subject to such a program, the term "permitting authority" shall mean the permitting authority under an applicable State or federal NO_X mass emission reduction program that adopts the requirements of this subpart, and the term "designated representative" shall mean the responsible party under the applicable State or federal NO_X mass emission reduction program that adopts the requirements of this subpart.

(2) In addition, the provisions of subparts A, C, D, E, F, and G and appendices A through G of this part applicable to NO_X concentration, flow rate, NO_X emission rate and heat input, as set forth and referenced in this subpart, shall apply to the owner or operator of a unit required to meet the requirements of this subpart by a State or federal NO_X mass emission reduction program. When applying these requirements, the term "affected unit" shall mean any unit that is subject to a State or federal NO_X mass emission reduction program requiring compliance with this subpart, the term "permitting authority" shall mean the permitting authority under an applicable State or federal NO_X mass emission reduction program that adopts the requirements of this subpart, and the term "designated representative" shall mean the responsible party under the applicable State or federal NO_X mass emission reduction program that adopts the requirements of this subpart. The requirements of this part for SO_2, CO_2 and opacity monitoring, recordkeeping and reporting do not apply to units that are subject to a State or federal NO_X mass emission reduction program only and are not affected units with an Acid Rain emission limitation.

(b) *Compliance dates.* The owner or operator of an affected unit shall meet the compliance deadlines established by an applicable State or federal NO_X mass emission reduction program that adopts the requirements of this subpart.

(c) *Prohibitions.* (1) No owner or operator of an affected unit or a non-affected unit under §75.72(b)(2)(ii) shall use any alternative monitoring system, alternative reference method, or any other alternative for the required continuous emission monitoring system without having obtained prior written approval in accordance with paragraph (h) of this section.

(2) No owner or operator of an affected unit or a non-affected unit under §75.72(b)(2)(ii) shall operate the unit so as to discharge, or allow to be discharged emissions of NO_X to the atmosphere without accounting for all such emissions in accordance with the applicable provisions of this part, except as provided in §75.74.

(3) No owner or operator of an affected unit or a non-affected unit under §75.72(b)(2)(ii) shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method, and thereby avoid monitoring and recording NO_X mass emissions discharged into the atmosphere, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the provisions of this part applicable to monitoring systems under §75.71, except as provided in §75.74.

(4) No owner or operator of an affected unit or a non-affected unit under §75.72(b)(2)(ii) shall retire or permanently discontinue use of the continuous emission monitoring system, any component thereof, or any other approved emission monitoring system under this part, except under any one of the following circumstances:

(i) During the period that the unit is covered by a retired unit exemption that is in effect under the State or federal NO_X mass emission reduction program that adopts the requirements of this subpart;

(ii) The owner or operator is monitoring NO_X mass emissions from the affected unit with another certified monitoring system approved, in accordance with the provisions of paragraph (d) of this section; or

(iii) The designated representative submits notification of the date of certification testing of a replacement monitoring system in accordance with §75.61.

(d) *Initial certification and recertification procedures.* (1) The owner or operator of an affected unit that is subject to an Acid Rain emissions limitation shall comply with the initial certification and recertification procedures in §75.20 of this part, except that the owner or operator shall meet any additional requirements set forth in an applicable State or federal NO_X mass emission reduction program that adopts the requirements of this subpart.

(2) The owner or operator of an affected unit that is not subject to an Acid Rain emissions limitation shall comply with the initial certification and recertification procedures established by an applicable State or federal NO_X mass emission reduction program that adopts the requirements of this subpart. The owner or operator of an affected unit that is subject to an Acid Rain emissions limitation shall comply with the initial certification and recertification procedures established by an applicable State or federal NO_X mass emission reduction program that adopts the requirements of this subpart for any additional NO_X-diluent CEMS, flow monitors, diluent monitors or NO_X concentration monitoring system required under the NO_X mass emissions provisions of §75.71 or the common stack provisions in §75.72.

(e) *Quality assurance and quality control requirements.* For units that use continuous emission monitoring systems to account for NO_X mass emissions, the owner or operator shall meet the applicable quality assurance and quality control requirements in §75.21, appendix B to this part, and §75.74(c) for the NO_X-diluent continuous emission monitoring systems, flow monitoring systems, NO_X concentration monitoring systems, moisture monitoring systems, and diluent monitors required under §75.71. Units using the low mass emissions excepted methodology under §75.19 shall meet the applicable quality assurance requirements of that section, except as otherwise provided in §75.74(c). Units using excepted monitoring methods under appendices D and E to this part shall meet the applicable quality assurance requirements of those appendices.

(f) *Missing data procedures.* Except as provided in §75.34, paragraph (g) of this section, and §75.74(c)(7), the owner or operator shall provide substitute data from monitoring systems required under §75.71 for each affected unit as follows:

(1) For an owner or operator using a continuous emissions monitoring system, substitute for missing data in accordance with the applicable missing data procedures in §§75.31 through 75.37 whenever the unit combusts fuel and:

(i) A valid, quality-assured hour of NO_X emission rate data (in lb/mmBtu) has not been measured and recorded for a unit by a certified NO_X-diluent continuous emission monitoring system or by an approved monitoring system under subpart E of this part;

(ii) A valid, quality-assured hour of flow data (in scfh) has not been measured and recorded for a unit from a certified flow monitor or by an approved alternative monitoring system under subpart E of this part;

(iii) A valid, quality-assured hour of heat input rate data (in mmBtu/hr) has not been measured and recorded for a unit from a certified flow monitor and a certified diluent (CO_2 or O_2) monitor or by an approved alternative monitoring system under subpart E of this part, where heat input is required either for calculating NO_X mass or allocating allowances under the applicable State or federal NO_X mass emission reduction program that adopts the requirements of this subpart;

(iv) A valid, quality-assured hour of NO_X concentration data (in ppm) has not been measured and recorded by a certified NO_X concentration monitoring system, or by an approved alternative monitoring method under subpart E of this part, where the owner or operator chooses to use a NO_X concentration monitoring system with a flow monitor, to calculate NO_X mass emissions. The initial missing data procedures for determining monitor data availability and the standard missing data procedures for a NO_X concentration monitoring system shall be the same as the procedures specified for a NO_X-diluent continuous emission monitoring system under §§75.31, 75.32, and 75.33; or

(v) A valid, quality-assured hour of moisture data (in percent H_2O) has not been measured or recorded for an affected unit, either by a certified moisture monitoring system or an approved alternative monitoring method under subpart E of this part. This requirement does not apply when a default percent moisture value, as provided in §75.11(b) or §75.12(b), is used to account for the hourly moisture content of the stack gas.

(2) For an owner or operator using an excepted monitoring system under appendix D or E of this part, substitute for missing data in accordance with the missing data procedures in section 2.4 of appendix D to this part or in section 2.5 of appendix E to this part whenever the unit combusts fuel and:

(i) A valid, quality-assured hour of fuel flow rate data has not been measured and recorded by a certified fuel flowmeter that is part of an excepted monitoring system under appendix D or E of this part; or

(ii) A fuel sample value for gross calorific value, or if necessary, density or specific gravity, from a sample taken an analyzed in accordance with appendix D of this part is not available; or

(iii) A valid, quality-assured hour of NO_X emission rate data has not been obtained according to the procedures and specifications of appendix E to this part.

(g) *Reporting data prior to initial certification.* If the owner or operator of an affected unit has not successfully completed all certification tests required by the State or federal NO_X mass emission reduction program that adopts the requirements of this subpart by the applicable date required by that program, he or she shall determine, record and report hourly data prior to initial certification using one of the following procedures, consistent with the monitoring equipment to be certified:

(1) For units that the owner or operator intends to monitor for NO_X mass emissions using NO_X emission rate and heat input rate, the maximum potential NO_X emission rate and the maximum potential hourly heat input of the unit, as defined in §72.2 of this chapter.

(2) For units that the owner or operator intends to monitor for NO_X mass emissions using a NO_X concentration monitoring system and a flow monitoring system, the maximum potential concentration of NO_X and the maximum potential flow rate, as defined in section 2.1.4.1 of appendix A to this part;

(3) For any unit, the reference methods under §75.22 of this part.

(4) For any unit using the low mass emission excepted monitoring methodology under §75.19, the procedures in paragraphs (g)(1) or (2) of this section.

(5) Any unit using the procedures in paragraph (g)(2) of this section that is required to report heat input for purposes of allocating allowances shall also report the maximum potential hourly heat input of the unit, as defined in §72.2 of this chapter.

(6) For any unit using continuous emissions monitors, the conditional data validation procedures in §75.20(b)(3)(ii) through (b)(3)(ix).

(h) *Petitions.* (1) The designated representative of an affected unit that is subject to an Acid Rain emissions limitation may submit a petition to the Administrator requesting an alternative to any requirement of this subpart. Such a petition shall meet the requirements of §75.66 and any additional requirements established by an applicable State or federal NO_X mass emission reduction program that adopts the requirements of this subpart. Use of an alternative to any requirement of this subpart is in accordance with this subpart and with such State or federal NO_X mass emission reduction program only to the extent that the petition is approved by the Administrator, in consultation with the permitting authority.

(2) Notwithstanding paragraph (h)(1) of this section, petitions requesting an alternative to a requirement concerning any additional CEMS required solely to meet the common stack provisions of §75.72 shall be submitted to the permitting authority

and the Administrator and shall be governed by paragraph (h)(3)(ii) of this section. Such a petition shall meet the requirements of §75.66 and any additional requirements established by an applicable State or federal NO_X mass emission reduction program that adopts the requirements of this subpart.

(3)(i) The designated representative of an affected unit that is not subject to an Acid Rain emissions limitation may submit a petition to the permitting authority and the Administrator requesting an alternative to any requirement of this subpart. Such a petition shall meet the requirements of §75.66 and any additional requirements established by an applicable State or federal NO_X mass emission reduction program that adopts the requirements of this subpart.

(ii) Use of an alternative to any requirement of this subpart is in accordance with this subpart only to the extent that it is approved by the Administrator and by the permitting authority if required by an applicable State or federal NO_X mass emission reduction program that adopts the requirements of this subpart.

[63 FR 57507, Oct. 27, 1998, as amended at 64 FR 28624, May 26, 1999; 67 FR 40444, June 12, 2002]

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§75.71 Specific provisions for monitoring NO_X and heat input for the purpose of calculating NO_X mass emissions.

(a) *Coal-fired units.* The owner or operator of a coal-fired affected unit shall either:

(1) Meet the general operating requirements in §75.10 for a NO_X-diluent continuous emission monitoring system (consisting of a NO_X pollutant concentration monitor, an O_2 or CO_2 diluent gas monitor, and a data acquisition and handling system) to measure NO_X emission rate and for a flow monitoring system and an O_2 or CO_2 diluent gas monitoring system to measure heat input rate, except as provided in accordance with subpart E of this part; or

(2) Meet the general operating requirements in §75.10 for a NO_X concentration monitoring system (consisting of a NO_X pollutant concentration monitor and a data acquisition and handling system) to measure NO_X concentration and for a flow monitoring system. In addition, if heat input is required to be reported under the applicable State or federal NO_X mass emission reduction program that adopts the requirements of this subpart, the owner or operator also must meet the general operating requirements for a flow monitoring system and an O_2 or CO_2 monitoring system to measure heat input rate. These requirements must be met, except as provided in accordance with subpart E of this part.

(b) *Moisture correction.* (1) If a correction for the stack gas moisture content is needed to properly calculate the NO_X emission rate in lb/mmBtu (e.g., if the NO_X pollutant concentration monitor in a NO_X-diluent monitoring system measures on a different moisture basis from the diluent monitor), or to calculate the heat input rate, the owner or operator of an affected unit shall account for the moisture content of the flue gas on a continuous basis in accordance with §75.12(b).

(2) If a correction for the stack gas moisture content is needed to properly calculate NO_X mass emissions in tons, in the case where a NO_X concentration monitoring system which measures on a dry basis is used with a flow rate monitor to determine NO_X mass emissions, the owner or operator of an affected unit shall account for the moisture content of the flue gas on a continuous basis in accordance with §75.11(b) except that the term "SO_2" shall be replaced by the term "NO_X."

(3) If a correction for the stack gas moisture content is needed to properly calculate NO_X mass emissions, in the case where a diluent monitor that measures on a dry basis is used with a flow rate monitor to determine heat input rate, which is then multiplied by the NO_X emission rate, the owner or operator shall install, operate, maintain, and quality assure a continuous moisture monitoring system, as described in §75.11(b).

(c) *Gas-fired nonpeaking units or oil-fired nonpeaking units.* The owner or operator of an affected unit that, based on information submitted by the designated representative in the monitoring plan, qualifies as a gas-fired or oil-fired unit but not as a peaking unit, as defined in §72.2 of this chapter, shall either:

(1) Meet the requirements of paragraph (a) of this section and, if applicable, paragraph (b) of this section; or

(2) Meet the general operating requirements in §75.10 for a NO_X-diluent continuous emission monitoring system, except as provided in accordance with subpart E of this part, and use the procedures specified in appendix D to this part for determining hourly heat input rate. However, for a common pipe configuration, the heat input rate apportionment provisions in section 2.1.2 of appendix D to this part shall not be used to meet the NO_X mass reporting provisions of this subpart, unless all of the units served by the common pipe are affected units and have similar efficiencies; or

(3) Meet the requirements of the low mass emission excepted methodology under paragraph (e)(2) of this section and under §75.19, if applicable.

(d) *Gas-fired or oil-fired peaking units.* The owner or operator of an affected unit that qualifies as a peaking unit and as either gas-fired or oil-fired, as defined in §72.2 of this chapter, based on information submitted by the designated representative in the monitoring plan, shall either:

(1) Meet the requirements of paragraph (c) of this section; or

(2) Use the procedures in appendix D to this part for determining hourly heat input and the procedure specified in appendix E to this part for estimating hourly NO_X emission rate. However, for a common pipe configuration, the heat input apportionment provisions in section 2.1.2 of appendix D to this part shall not be used to meet the NO_X mass reporting provisions of this subpart unless all of the units served by the common pipe are affected units and have similar efficiencies. In addition, if after certification of an excepted monitoring system under appendix E to this part, the operation of a unit that reports emissions on an annual basis under §75.74(a) of this part exceeds a capacity factor of 20.0 percent in any calendar year or exceeds an annual capacity factor of 10.0 percent averaged over three years, or the operation of a unit that reports emissions on an ozone season basis under §75.74(b) of this part exceeds a capacity factor of 20.0 percent in any ozone season or exceeds an ozone season capacity factor of 10.0 percent averaged over three years, the owner or operator shall meet the requirements of paragraph (c)(1) or (c)(2) of this section by no later than December 31 of the following calendar year. If the required CEMS are not installed and certified by that date, the owner or operator shall report hourly NO_X mass emissions as the product of the maximum potential NO_X emission rate (MER) and the maximum hourly heat input of the unit (as defined in §72.2 of this chapter), starting with the first unit operating hour after the deadline and continuing until the CEMS are provisionally certified.

(e) *Low mass emissions units.* Notwithstanding the requirements of paragraphs (c) and (d) of this section, for an affected unit using the low mass emissions (LME) unit under §75.19 to estimate hourly NO_X emission rate, heat input and NO_X mass emissions, the owner or operator shall calculate the ozone season NO_X mass emissions by summing all of the estimated hourly NO_X mass emissions in the ozone season, as determined under §75.19 (c)(4)(ii)(A), and dividing this sum by 2000 lb/ton.

(f) *Other units.* The owner or operator of an affected unit that combusts wood, refuse, or other materials shall comply with the monitoring provisions specified in paragraph (a) of this section and, where applicable, paragraph (b) of this section.

[63 FR 57508, Oct. 27, 1998, as amended at 64 FR 28624, May 26, 1999; 67 FR 40444, 40445, June 12, 2002; 67 FR 53505, Aug. 16, 2002; 73 FR 4358, Jan. 24, 2008]

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§75.72 Determination of NO_X mass emissions for common stack and multiple stack configurations.

The owner or operator of an affected unit shall either: calculate hourly NO_X mass emissions (in lbs) by multiplying the hourly NO_X emission rate (in lbs/mmBtu) by the hourly heat input rate (in mmBtu/hr) and the unit or stack operating time (as defined in §72.2), or, as provided in paragraph (e) of this section, calculate hourly NO_X mass emissions from the hourly NO_X concentration (in ppm) and the hourly stack flow rate (in scfh). Only one methodology for determining NO_X mass emissions shall be identified in the monitoring plan for each monitoring location at any given time. The owner or operator shall also calculate quarterly and cumulative year-to-date NO_X mass emissions and cumulative NO_X mass emissions for the ozone season (in tons) by summing the hourly NO_X mass emissions according to the procedures in section 8 of appendix F to this part.

(a) *Unit utilizing common stack with other affected unit(s).* When an affected unit utilizes a common stack with one or more affected units, but no nonaffected units, the owner or operator shall either:

(1) Install, certify, operate, and maintain a NO_X-diluent continuous emissions monitoring system and a flow monitoring system in the common stack, record the combined NO_X mass emissions for the units exhausting to the common stack, and, for purposes of determining the hourly unit heat input rates, either:

(i) Apportion the common stack heat input rate to the individual units according to the procedures in §75.16(e)(3); or

(ii) Install, certify, operate, and maintain a flow monitoring system and diluent monitor in the duct to the common stack from each unit; or

(iii) If any of the units using the common stack are eligible to use the procedures in appendix D to this part,

(A) Use the procedures in appendix D to this part to determine heat input rate for that unit; and

(B) Install, certify, operate, and maintain a flow monitoring system and a diluent monitor in the duct to the common stack for each remaining unit; or

(2) Install, certify, operate, and maintain a NO_X-diluent continuous emissions monitoring system in the duct to the common stack from each unit and, for purposes of heat input determination, either:

(i) Install, certify, operate, and maintain a flow monitoring system in the duct to the common stack from each unit; or

(ii) For any unit using the common stack and eligible to use the procedures in appendix D to this part,

(A) Use the procedures in appendix D to determine heat input rate for that unit; and

(B) Install, certify, operate, and maintain a flow monitoring system in the duct to the common stack for each remaining unit.

(b) *Unit utilizing common stack with nonaffected unit(s).* When one or more affected units utilizes a common stack with one or more nonaffected units, the owner or operator shall either:

(1) Install, certify, operate, and maintain a NO_X-diluent continuous emission monitoring system in the duct to the common stack from each affected unit and, for purposes of heat input determination,

(i) Install, certify, operate, and maintain a flow monitoring system in the duct to the common stack from each affected unit; or

(ii) For any affected unit using the common stack and eligible to use the procedures in appendix D to this part,

(A) Use the procedures in appendix D to determine heat input for that unit; however, for a common pipe configuration, the heat input apportionment provisions in section 2.1.2 of appendix D to this part shall not be used to meet the NO_X mass reporting provisions of this subpart unless all of the units served by the common pipe are affected units and have similar efficiencies; and

(B) Install, certify, operate, and maintain a flow monitoring system in the duct to the common stack for each remaining affected unit that exhausts to the common stack; or

(2) Install, certify, operate, and maintain a NO_X-diluent continuous emission monitoring system in the common stack; and

(i) Designate the nonaffected units as affected units in accordance with the applicable State or federal NO_X mass emissions reduction program and meet the requirements of paragraph (a)(1) of this section; or

(ii) Install, certify, operate, and maintain a flow monitoring system in the common stack and a NO_X-diluent continuous emission monitoring system in the duct to the common stack from each nonaffected unit. The designated representative shall submit a petition to the permitting authority and the Administrator to allow a method of calculating and reporting the NO_X mass emissions from the affected units as the difference between NO_X mass emissions measured in the common stack and NO_X mass emissions measured in the ducts of the nonaffected units, not to be reported as an hourly value less than zero. The permitting authority and the Administrator may approve such a method whenever the designated representative demonstrates, to the satisfaction of the permitting authority and the Administrator, that the method ensures that the NO_X mass emissions from the affected units are not underestimated. In addition, the owner or operator shall also either:

(A) Install, certify, operate, and maintain a flow monitoring system in the duct from each nonaffected unit or,

(B) For any nonaffected unit exhausting to the common stack and otherwise eligible to use the procedures in appendix D to this part, determine heat input rate using the procedures in appendix D for that unit. However, for a common pipe serving both affected and non-affected units, the heat input rate apportionment provisions in section 2.1.2 of appendix D to this part shall not be used to meet the NO_X mass reporting provisions of this subpart. For any remaining nonaffected unit that exhausts to the common stack, install, certify, operate, and maintain a flow monitoring system in the duct to the common stack; or

(iii) Install a flow monitoring system in the common stack and record the combined emissions from all units as the combined NO_X mass emissions for the affected units for recordkeeping and compliance purposes, in accordance with paragraph (a) of this section; or

(iv) Submit a petition to the permitting authority and the Administrator to allow use of a method for apportioning NO_X mass emissions measured in the common stack to each of the units using the common stack and for reporting the NO_X mass emissions. The permitting authority and the Administrator may approve such a method whenever the designated representative demonstrates, to the satisfaction of the permitting authority and the Administrator, that the method ensures that the NO_X mass emissions from the affected units are not underestimated.

(c) *Unit with a main stack and a bypass stack.* Whenever any portion of the flue gases from an affected unit can be routed through a bypass stack to avoid the installed NO_X-diluent continuous emissions monitoring system or NO_X concentration monitoring system, the owner and operator shall either:

(1) Install, certify, operate, and maintain separate NO_X-diluent continuous emissions monitoring systems and flow monitoring systems on the main stack and the bypass stack and calculate NO_X mass emissions for the unit as the sum of the NO_X mass emissions measured at the two stacks;

(2) Monitor NO_X mass emissions at the main stack using a NO_X-diluent CEMS and a flow monitoring system and measure NO_X mass emissions at the bypass stack using the reference methods in §75.22(b) for NO_X concentration, flow rate, and diluent gas concentration, or NO_X concentration and flow rate, and calculate NO_X mass emissions for the unit as the sum of the emissions recorded by the installed monitoring systems on the main stack and the emissions measured by the reference method monitoring systems; or

(3) Install, certify, operate, and maintain a NO_X-diluent CEMS and a flow monitoring system only on the main stack. If this option is chosen, it is not necessary to designate the exhaust configuration as a multiple stack configuration in the monitoring plan required under §75.53, since only the main stack is monitored. For each unit operating hour in which the bypass stack is used and the emissions are either uncontrolled (or the add-on controls are not documented to be operating properly), report NO_X mass emissions as follows. If the unit heat input is determined using a flow monitor and a diluent monitor, report NO_X mass emissions using the maximum potential NO_X emission rate, the maximum potential flow rate, and either the maximum potential CO_2 concentration or the minimum potential O_2 concentration (as applicable). The maximum potential NO_X emission rate may be specific to the type of fuel combusted in the unit during the bypass (see §75.33(c)(8)). If the unit heat input is determined using a fuel flowmeter, in accordance with appendix D to this part, report NO_X mass emissions as the product of the maximum potential NO_X emission rate and the actual measured hourly heat input rate. Alternatively, for a unit with NO_X add-on emission controls, for each unit operating hour in which the bypass stack is used but the add-on NO_X emission controls are not bypassed, the owner or operator may report the maximum controlled NO_X emission rate (MCR) instead of the maximum potential NO_X emission rate provided that the add-on controls are documented to be operating properly, as described in the quality assurance/quality control program for the unit, required by section 1 in appendix B of this part. To provide the necessary documentation, the owner or operator shall record parametric data to verify the proper operation of the NO_X add-on emission controls as described in §75.34(d). Furthermore, the owner or operator shall calculate the MCR using the procedure described in section 2.1.2.1(b) of appendix A to this part by replacing the words "maximum potential NO_X emission rate (MER)" with the words "maximum controlled NO_X emission rate (MCR)" and by using the NO_X MEC in the calculations instead of the NO_X MPC.

(d) *Unit with multiple stack or duct configuration.* When the flue gases from an affected unit discharge to the atmosphere through more than one stack, or when the flue gases from an affected unit utilize two or more ducts feeding into a single stack and the owner or operator chooses to monitor in the ducts rather than in the stack, the owner or operator shall either:

(1) Install, certify, operate, and maintain a NO_X-diluent continuous emission monitoring system and a flow monitoring system in each of the multiple stacks and determine NO_X mass emissions from the affected unit as the sum of the NO_X mass emissions recorded for each stack. If another unit also exhausts flue gases into one of the monitored stacks, the owner or operator shall comply with the applicable requirements of paragraphs (a) and (b) of this section, in order to properly determine the NO_X mass emissions from the units using that stack;

(2) Install, certify, operate, and maintain a NO_X-diluent continuous emissions monitoring system and a flow monitoring system in each of the ducts that feed into the stack, and determine NO_X mass emissions from the affected unit using the sum of the NO_X mass emissions measured at each duct; or

(3) If the unit is eligible to use the procedures in appendix D to this part and if the conditions and restrictions of §75.17(c)(2) are fully met, install, certify, operate, and maintain a NO_X-diluent continuous emissions monitoring system in one of the ducts feeding into the stack or in one of the multiple stacks, (as applicable) in accordance with §75.17(c)(2), and use the procedures in appendix D to this part to determine heat input rate for the unit.

(e) *Units using a NO_X concentration monitoring system and a flow monitoring system to determine NO_X mass.* The owner or operator may use a NO_X concentration monitoring system and a flow monitoring system to determine NO_X mass emissions for the cases described in paragraphs (a) through (c) of this section and in paragraph (d)(1) or paragraph (d)(2) of this section (in place of a NO_X-diluent continuous emissions monitoring system and a flow monitoring system). However, this option may not be used for the case described in paragraph (d)(3) of this section. When using this approach, calculate NO_X mass according to sections 8.2 and 8.3 in appendix F to this part. In addition, if an applicable State or federal NO_X mass reduction program requires determination of a unit's heat input, the owner or operator must either:

(1) Install, certify, operate, and maintain a CO_2 or O_2 diluent monitor in the same location as each flow monitoring system. In addition, the owner or operator must provide heat input rate values for each unit utilizing a common stack. The owner or operator may either:

(i) Apportion heat input rate from the common stack to each unit according to §75.16(e)(3), where all units utilizing the common stack are affected units, or

(ii) Measure heat input from each affected unit, using a flow monitor and a CO_2 or O_2 diluent monitor in the duct from each affected unit; or

(2) For units that are eligible to use appendix D to this part, use the procedures in appendix D to this part to determine heat input rate for the unit. However, the use of a fuel flowmeter in a common pipe header and the provisions of sections 2.1.2.1 and 2.1.2.2 of appendix D of this part are not applicable to any unit that is using the provisions of this subpart to monitor, record, and report NO_X mass emissions under a State or federal NO_X mass emission reduction program and that shares a common pipe with a nonaffected unit.

(f) [Reserved]

(g) *Procedures for apportioning heat input to the unit level.* If the owner or operator of a unit using the common stack monitoring provisions in paragraphs (a) or (b) of this section does not monitor and record heat input at the unit level and the owner or operator is required to do so under an applicable State or federal NO_X mass emission reduction program, apportion heat input from the common stack to each unit according to §75.16(e)(3).

[63 FR 57507, Oct. 27, 1998, as amended at 67 FR 40445, June 12, 2002; 73 FR 4358, Jan. 24, 2008]

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§75.73 Recordkeeping and reporting.

(a) *General recordkeeping provisions.* The owner or operator of any affected unit shall maintain for each affected unit and each non-affected unit under §75.72(b)(2)(ii) a file of all measurements, data, reports, and other information required by this part at the source in a form suitable for inspection for at least three (3) years from the date of each record. Except for the certification data required in §75.57(a)(4) and the initial submission of the monitoring plan required in §75.57(a)(5), the data shall be collected beginning with the earlier of the date of provisional certification or the compliance deadline in §75.70(b). The certification data required in §75.57(a)(4) shall be collected beginning with the date of the first certification test performed. The file shall contain the following information:

(1) The information required in §§75.57(a)(2), (a)(4), (a)(5), (a)(6), (b), (c)(2), (d), (g), and (h).

(2) The information required in §§75.58(b)(2) or (b)(3) (for units with add-on NO_X emission controls), as applicable, (d) (as applicable for units using Appendix E to this part), and (f) (as applicable for units using the low mass emissions unit provisions of §75.19).

(3) For each hour when the unit is operating, NO_X mass emissions, calculated in accordance with section 8.1 of appendix F to this part.

(4) During the second and third calendar quarters, cumulative ozone season heat input and cumulative ozone season operating hours.

(5) Heat input and NO_X methodologies for the hour.

(6) *Specific heat input record provisions for gas-fired or oil-fired units using the procedures in appendix D to this part.* In lieu of the information required in §75.57(c)(2), the owner or operator shall record the information in §75.58(c) for each affected gas-fired or oil-fired unit and each non-affected gas- or oil-fired unit under §75.72(b)(2)(ii) for which the owner or operator is using the procedures in appendix D to this part for estimating heat input.

(7) *Specific NO_X record provisions for gas-fired or oil-fired units using the optional low mass emissions excepted methodology in §75.19.* In lieu of recording the information in §§75.57(b), (c)(2), (d), and (g), the owner or operator shall record, for each hour when the unit is operating for any portion of the hour, the following information for each affected low mass emissions unit for which the owner or operator is using the low mass emissions excepted methodology in §75.19(c):

(i) Date and hour;

(ii) If one type of fuel is combusted in the hour, fuel type (pipeline natural gas, natural gas, residual oil, or diesel fuel) or, if more than one type of fuel is combusted in the hour, the fuel type which results in the highest emission factors for NO_X;

(iii) Average hourly NO_X emission rate (in lb/mmBtu, rounded to the nearest thousandth); and

(iv) Hourly NO_X mass emissions (in lbs, rounded to the nearest tenth).

(8) Formulas from monitoring plan for total NO_X mass.

(b) *Certification, quality assurance and quality control record provisions.* The owner or operator of any affected unit shall record the applicable information in §75.59 for each affected unit or group of units monitored at a common stack and each non-affected unit under §75.72(b)(2)(ii).

(c) *Monitoring plan recordkeeping provisions*—(1) *General provisions.* The owner or operator of an affected unit shall prepare and maintain a monitoring plan for each affected unit or group of units monitored at a common stack and each non-affected unit under §75.72(b)(2)(ii). Except as provided in paragraph (d) or (f) of this section, a monitoring plan shall contain sufficient information on the continuous emission monitoring systems, excepted methodology under §75.19, or excepted monitoring systems under appendix D or E to this part and the use of data derived from these systems to demonstrate that all the unit's No_X emissions are monitored and reported.

(2) Whenever the owner or operator makes a replacement, modification, or change in the certified continuous emission monitoring system, excepted methodology under §75.19, excepted monitoring system under appendix D or E to this part, or alternative monitoring system under subpart E of this part, including a change in the automated data acquisition and handling system or in the flue gas handling system, that affects information reported in the monitoring plan (e.g., a change to a serial number for a component of a monitoring system), then the owner or operator shall update the monitoring plan.

(3) *Contents of the monitoring plan for units not subject to an Acid Rain emissions limitation.* Prior to January 1, 2009, each monitoring plan shall contain the information in §75.53(e)(1) or §75.53(g)(1) in electronic format and the information in §75.53(e)(2) or §75.53(g)(2) in hardcopy format. On and after January 1, 2009, each monitoring plan shall contain the information in §75.53(g)(1) in electronic format and the information in §75.53(g)(2) in hardcopy format, only. In addition, to the extent applicable, prior to January 1, 2009, each monitoring plan shall contain the information in §75.53(f)(1)(i), (f)(2)(i), and (f)(4) or §75.53(h)(1)(i), and (h)(2)(i) in electronic format and the information in §75.53(f)(1)(ii) and (f)(2)(ii) or §75.53(h)(1)(ii) and (h)(2)(ii) in hardcopy format. On and after January 1, 2009, each monitoring plan shall contain the information in §75.53(h)(1)(i), and (h)(2)(i) in electronic format and the information in §75.53(h)(1)(ii) and (h)(2)(ii) in hardcopy format, only. For units using the low mass emissions excepted methodology under §75.19, prior to January 1, 2009, the monitoring plan shall include the additional information in §75.53(f)(5)(i) and (f)(5)(ii) or §75.53(h)(4)(i) and (h)(4)(ii). On and after January 1, 2009, for units using the low mass emissions excepted methodology under §75.19 the monitoring plan shall include the additional information in §75.53(h)(4)(i) and (h)(4)(ii), only. Prior to January 1, 2008, the monitoring plan shall also identify, in electronic format, the reporting schedule for the affected unit (ozone season or quarterly), and the beginning and end dates for the reporting schedule. The monitoring plan also shall include a seasonal controls indicator, and an ozone season fuel-switching flag.

(d) *General reporting provisions.* (1) The designated representative for an affected unit shall comply with all reporting requirements in this section and with any additional requirements set forth in an applicable State or federal NO_X mass emission reduction program that adopts the requirements of this subpart.

(2) The designated representative for an affected unit shall submit the following for each affected unit or group of units monitored at a common stack and each non-affected unit under §75.72(b)(2)(ii):

(i) Initial certification and recertification applications in accordance with §75.70(d);

(ii) Monitoring plans in accordance with paragraph (e) of this section; and

(iii) Quarterly reports in accordance with paragraph (f) of this section.

(3) *Other petitions and communications.* The designated representative for an affected unit shall submit petitions, correspondence, application forms, and petition-related test results in accordance with the provisions in §75.70(h).

(4) *Quality assurance RATA reports.* If requested by the permitting authority, the designated representative of an affected unit shall submit the quality assurance RATA report for each affected unit or group of units monitored at a common stack and each non-affected unit under §75.72(b)(2)(ii) by the later of 45 days after completing a quality assurance RATA according to section 2.3 of appendix B to this part or 15 days of receiving the request. The designated representative shall report the hardcopy information required by §75.59(a)(9) to the permitting authority.

(5) *Notifications.* The designated representative for an affected unit shall submit written notice to the permitting authority according to the provisions in §75.61 for each affected unit or group of units monitored at a common stack and each non-affected unit under §75.72(b)(2)(ii).

(6) *Routine appendix E retest reports.* If requested by the applicable EPA Regional Office, appropriate State, and/or appropriate local air pollution control agency, the designated representative shall submit a hardcopy report within 45 days after completing a required periodic retest according to section 2.2 of appendix E to this part, or within 15 days of receiving the request, whichever is later. The designated representative shall report the hardcopy information required by §75.59(b)(5) to the

applicable EPA Regional Office, appropriate State, and/or appropriate local air pollution control agency that requested the hardcopy report.

(e) *Monitoring plan reporting*—(1) *Electronic submission.* The designated representative for an affected unit shall submit to the Administrator a complete, electronic, up-to-date monitoring plan file for each affected unit or group of units monitored at a common stack and each non-affected unit under §75.72(b)(2)(ii), no later than 21 days prior to the initial certification test; at the time of a certification or recertification application submission; and whenever an update of the electronic monitoring plan is required, either under §75.53 or elsewhere in this part.

(2) *Hardcopy submission.* The designated representative of an affected unit shall submit all of the hardcopy information required under §75.53, for each affected unit or group of units monitored at a common stack and each non-affected unit under §75.72(b)(2)(ii), to the permitting authority prior to initial certification. Thereafter, the designated representative shall submit hardcopy information only if that portion of the monitoring plan is revised. The designated representative shall submit the required hardcopy information as follows: no later than 21 days prior to the initial certification test; with any certification or recertification application, if a hardcopy monitoring plan change is associated with the recertification event; and within 30 days of any other event with which a hardcopy monitoring plan change is associated, pursuant to §75.53(b). Electronic submittal of all monitoring plan information, including hardcopy portions, is permissible provided that a paper copy of the hardcopy portions can be furnished upon request.

(f) *Quarterly reports*—(1) *Electronic submission.* The designated representative for an affected unit shall electronically report the data and information in this paragraph (f)(1) and in paragraphs (f)(2) and (3) of this section to the Administrator quarterly, unless the unit has been placed in long-term cold storage (as defined in §72.2 of this chapter). For units placed into long-term cold storage during a reporting quarter, the exemption from submitting quarterly reports begins with the calendar quarter following the date that the unit is placed into long-term cold storage. In such cases, the owner or operator shall submit quarterly reports for the unit beginning with the data from the quarter in which the unit recommences operation (where the initial quarterly report contains hourly data beginning with the first hour of recommenced operation of the unit). Each electronic report must be submitted to the Administrator within 30 days following the end of each calendar quarter. Except as otherwise provided in §75.64(a)(4) and (a)(5), each electronic report shall include the information provided in paragraphs (f)(1)(i) through (1)(vi) of this section, and shall also include the date of report generation. Prior to January 1, 2009, each report shall include the facility information provided in paragraphs (f)(1)(i)(A) and (B) of this section, for each affected unit or group of units monitored at a common stack. On and after January 1, 2009, only the facility identification information provided in paragraph (f)(1)(i)(A) of this section is required.

(i) Facility information:

(A) Identification, including:

(*1*) Facility/ORISPL number;

(*2*) Calendar quarter and year data contained in the report; and

(*3*) Electronic data reporting format version used for the report.

(B) Location of facility, including:

(*1*) Plant name and facility identification code;

(*2*) EPA AIRS facility system identification code;

(*3*) State facility identification code;

(*4*) Source category/type;

(*5*) Primary SIC code;

(*6*) State postal abbreviation;

(*7*) FIPS county code; and

(*8*) Latitude and longitude.

(ii) The information and hourly data required in paragraphs (a) and (b) of this section, except for:

(A) Descriptions of adjustments, corrective action, and maintenance;

(B) Information which is incompatible with electronic reporting (e.g., field data sheets, lab analyses, quality control plan);

(C) For units with NO_X add-on emission controls that do not elect to use the approved site-specific parametric monitoring procedures for calculation of substitute data, the information in §75.58(b)(3);

(D) Information required by §75.57(h) concerning the causes of any missing data periods and the actions taken to cure such causes;

(E) Hardcopy monitoring plan information required by §75.53 and hardcopy test data and results required by §75.59;

(F) Records of flow polynomial equations and numerical values required by §75.59(a)(5)(vi);

(G) Daily fuel sampling information required by §75.58(c)(3)(i) for units using assumed values under appendix D;

(H) Information required by §75.59(b)(2) concerning transmitter or transducer accuracy tests;

(I) Stratification test results required as part of the RATA supplementary records under §75.59(a)(7);

(J) Data and results of RATAs that are aborted or invalidated due to problems with the reference method or operational problems with the unit and data and results of linearity checks that are aborted or invalidated due to operational problems with the unit; and

(K) Supplementary RATA information required under §75.59(a)(7), except that:

(*1*) The applicable data elements under §75.59(a)(7)(ii)(A) through (T) and under §75.59(a)(7)(iii)(A) through (M) shall be reported for flow RATAs at circular or rectangular stacks (or ducts) in which angular compensation for yaw and/or pitch angles is used (*i.e.*, Method 2F or 2G in appendices A-1 and A-2 to part 60 of this chapter), with or without wall effects adjustments;

(*2*) The applicable data elements under §75.59(a)(7)(ii)(A) through (T) and under §75.59(a)(7)(iii)(A) through (M) shall be reported for any flow RATA run at a circular stack in which Method 2 in appendices A-1 and A-2 to part 60 of this chapter is used and a wall effects adjustment factor is determined by direct measurement;

(*3*) The data under §75.59(a)(7)(ii)(T) shall be reported for all flow RATAs at circular stacks in which Method 2 in appendices A-1 and A-2 to part 60 of this chapter is used and a default wall effects adjustment factor is applied; and

(*4*) The data under §75.59(a)(7)(ix)(A) through (F) shall be reported for all flow RATAs at rectangular stacks or ducts in which Method 2 in appendices A-1 and A-2 to part 60 of this chapter is used and a wall effects adjustment factor is applied.

(iii) Average NO_X emission rate (lb/mmBtu, rounded to the nearest thousandth) during the quarter and cumulative NO_X emission rate for the calendar year.

(iv) Tons of NO_X emitted during quarter, cumulative tons of NO_X emitted during the year, and, during the second and third calendar quarters, cumulative tons of NO_X emitted during the ozone season.

(v) During the second and third calendar quarters, cumulative heat input for the ozone season.

(vi) Unit or stack or common pipe header operating hours for quarter, cumulative unit, stack or common pipe header operating hours for calendar year, and, during the second and third calendar quarters, cumulative operating hours during the ozone season.

(vii) Reporting period heat input.

(viii) New reporting frequency and begin date of the new reporting frequency (if applicable).

(2) The designated representative shall certify that the component and system identification codes and formulas in the quarterly electronic reports submitted to the Administrator pursuant to paragraph (e) of this section represent current operating conditions.

(3) *Compliance certification.* The designated representative shall submit and sign a compliance certification in support of each quarterly emissions monitoring report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit's emissions are correctly and fully monitored. The certification shall state that:

(i) The monitoring data submitted were recorded in accordance with the applicable requirements of this part, including the quality assurance procedures and specifications; and

(ii) With regard to a unit with add-on emission controls and for all hours where data are substituted in accordance with §75.34(a)(1), the add-on emission controls were operating within the range of parameters listed in the monitoring plan and the substitute values do not systematically underestimate NO_X emissions.

(4) The designated representative shall comply with all of the quarterly reporting requirements in §§75.64(d), (f), and (g).

[64 FR 28624, May 26, 1999, as amended at 67 FR 40446, June 12, 2002; 73 FR 4359, Jan. 24, 2008]

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§75.74 Annual and ozone season monitoring and reporting requirements.

(a) *Annual monitoring requirement.* (1) The owner or operator of an affected unit subject both to an Acid Rain emission limitation and to a State or federal NO_X mass reduction program that adopts the provisions of this part must meet the requirements of this part during the entire calendar year.

(2) The owner or operator of an affected unit subject to a State or federal NO_X mass reduction program that adopts the provisions of this part and that requires monitoring and reporting of hourly emissions on an annual basis must meet the requirements of this part during the entire calendar year.

(b) *Ozone season monitoring requirements.* The owner or operator of an affected unit that is not required to meet the requirements of this subpart on an annual basis under paragraph (a) of this section may either:

(1) Meet the requirements of this subpart on an annual basis; or

(2) Meet the requirements of this subpart during the ozone season, except as specified in paragraph (c) of this section.

(c) If the owner or operator of an affected unit chooses to meet the requirements of this subpart on less than an annual basis in accordance with paragraph (b)(2) of this section, then:

(1) The owner or operator of a unit that uses continuous emissions monitoring systems or a fuel flowmeter to meet any of the requirements of this subpart shall quality assure the hourly ozone season emission data required by this subpart. To achieve this, the owner or operator shall operate, maintain and calibrate each required CEMS and shall perform diagnostic testing and quality assurance testing of each required CEMS or fuel flowmeter according to the applicable provisions of paragraphs (c)(2) through (c)(5) of this section. Except where otherwise noted, the provisions of paragraphs (c)(2) and (c)(3) of this section apply instead of the quality assurance provisions in sections 2.1 through 2.3 of appendix B to this part, and shall be used in lieu of those appendix B provisions.

(2) *Quality assurance requirements prior to the ozone season.* The provisions of this paragraph apply to each ozone season. The owner or operator shall, at a minimum, perform the following diagnostic testing and quality assurance assessments, and shall maintain the following records, to ensure that the hourly emission data recorded at the beginning of the current ozone season are suitable for reporting as quality-assured data:

(i) For each required gas monitor (*i.e.*, for each NO_X pollutant concentration monitor and each diluent gas (CO_2 or O_2) monitor, including CO_2 and O_2 monitors used exclusively for heat input determination and O_2 monitors used for moisture determination), a linearity check shall be performed and passed in the second calendar quarter no later than April 30.

(A) Conduct each linearity check in accordance with the general procedures in section 6.2 of appendix A to this part, except that the data validation procedures in sections 6.2(a) through (f) of appendix A do not apply.

(B) Each linearity check shall be done “hands-off,” as described in section 2.2.3(c) of appendix B to this part.

(C) In the time period extending from the date and hour in which the linearity check is passed through April 30, the owner or operator shall operate and maintain the CEMS and shall perform daily calibration error tests of the CEMS in accordance with section 2.1 of appendix B to this part. When a calibration error test is failed, as described in section 2.1.4 of appendix B to this part, corrective actions shall be taken. The additional calibration error test provisions of section 2.1.3 of appendix B to this part shall be followed.

(D) If the linearity check is not completed by April 30, data validation shall be determined in accordance with paragraph (c)(3)(ii)(E) of this section.

(ii) For each required CEMS (*i.e.*, for each NO_X concentration monitoring system, each NO_X-diluent monitoring system, each flow rate monitoring system, each moisture monitoring system and each diluent gas CEMS used exclusively for heat input determination), a relative accuracy test audit (RATA) shall be performed and passed in the first or second calendar quarter, but no later than April 30.

(A) Conduct each RATA in accordance with the applicable procedures in sections 6.5 through 6.5.10 of appendix A to this part, except that the data validation procedures in sections 6.5(f)(1) through (f)(6) do not apply, and, for flow rate monitoring systems, the required RATA load level(s) (or operating level(s)) shall be as specified in this paragraph.

(B) Each RATA shall be done “hands-off,” as described in section 2.3.2 (c) of appendix B to this part. The provisions in section 2.3.1.4 of appendix B to this part, pertaining to the number of allowable RATA attempts, shall apply.

(C) For flow rate monitoring systems installed on peaking units or bypass stacks and for flow monitors exempted from multiple-level RATA testing under section 6.5.2(e) of appendix A to this part, a single-load (or single-level) RATA is required. For all other flow rate monitoring systems, a 2-load (or 2-level) RATA is required at the two most frequently-used load or operating levels (as defined under section 6.5.2.1 of appendix A to this part), with the following exceptions. Except for flow monitors exempted from 3-level RATA testing under section 6.5.2(e) of appendix A to this part, a 3-load flow RATA is required at least once every five years and is also required if the flow monitor polynomial coefficients or K factor(s) are changed prior to conducting the flow RATA required under this paragraph.

(D) A bias test of each required NO_X concentration monitoring system, each NO_X-diluent monitoring system and each flow rate monitoring system shall be performed in accordance with section 7.6 of appendix A to this part. If the bias test is failed, a bias adjustment factor (BAF) shall be calculated for the monitoring system, as described in section 7.6.5 of appendix A to this part and shall be applied to the subsequent data recorded by the CEMS.

(E) In the time period extending from the hour of completion of the required RATA through April 30, the owner or operator shall operate and maintain the CEMS by performing, at a minimum, the following activities:

(*1*) The owner or operator shall perform daily calibration error tests and (if applicable) daily flow monitor interference checks, according to section 2.1 of appendix B to this part. When a daily calibration error test or interference check is failed, as described in section 2.1.4 of appendix B to this part, corrective actions shall be taken. The additional calibration error test provisions in section 2.1.3 of appendix B to this part shall be followed. Records of the required daily calibration error tests and interference checks shall be kept in a format suitable for inspection on a year-round basis.

(*2*) If the owner or operator makes a replacement, modification, or change in a certified monitoring system that significantly affects the ability of the system to accurately measure or record NO_X mass emissions or heat input or to meet the requirements of §75.21 or appendix B to this part, the owner or operator shall recertify the monitoring system according to §75.20(b).

(F) *Data validation.* For each RATA that is performed by April 30, data validation shall be done according to sections 2.3.2(a)-(j) of appendix B to this part. However, if a required RATA is not completed by April 30, data from the monitoring system shall be invalid, beginning with the first unit operating hour on or after May 1. The owner or operator shall continue to invalidate all data from the CEMS until either:

(*1*) The required RATA of the CEMS has been performed and passed; or

(*2*) A probationary calibration error test of the CEMS is passed in accordance with §75.20(b)(3)(ii). Once the probationary calibration error test has been passed, the owner or operator shall perform the required RATA in accordance with the conditional data validation provisions and within the 720 unit or stack operating hour time frame specified in §75.20(b)(3) (subject to the restrictions in paragraph (c)(3)(xii) of this section), and the term “quality assurance” shall apply instead of the term “recertification.” However, in lieu of the provisions in §75.20(b)(3)(ix), the owner or operator shall follow the applicable provisions in paragraphs (c)(3)(xi) and (c)(3)(xii) of this section.

(3) *Quality assurance requirements within the ozone season.* The provisions of this paragraph apply to each ozone season. The owner or operator shall, at a minimum, perform the following quality assurance testing during the ozone season, i.e. in the time period extending from May 1 through September 30 of each calendar year:

(i) Daily calibration error tests and (if applicable) interference checks of each CEMS required by this subpart shall be performed in accordance with sections 2.1.1 and 2.1.2 of appendix B to this part. The applicable provisions in sections 2.1.3, 2.1.4 and 2.1.5 of appendix B to this part, pertaining, respectively, to additional calibration error tests and calibration adjustments, data validation, and quality assurance of data with respect to daily assessments, shall also apply.

(ii) For each gas monitor required by this subpart, linearity checks shall be performed in the second and third calendar quarters, as follows:

(A) For the second calendar quarter, the pre-ozone season linearity check required under paragraph (c)(2)(i) of this section shall be performed by April 30.

(B) For the third calendar quarter, a linearity check shall be performed and passed no later than July 30.

(C) Conduct each linearity check in accordance with the general procedures in section 6.2 of appendix A to this part, except that the data validation procedures in sections 6.2(a) through (f) of appendix A do not apply.

(D) Each linearity check shall be done “hands-off,” as described in section 2.2.3(c) of appendix B to this part.

(E) *Data Validation.* For second and third quarter linearity checks performed by the applicable deadline (*i.e.*, April 30 or July 30), data validation shall be done in accordance with sections 2.2.3(a), (b), (c), (e), and (h) of Appendix B to this part. However, if a required linearity check for the second calendar quarter is not completed by April 30, or if a required linearity check for the third calendar quarter is not completed by July 30, data from the monitoring system (or range) shall be invalid, beginning with the first unit operating hour on or after May 1 or July 31, respectively. The owner or operator shall continue to invalidate all data from the CEMS until either:

(*1*) The required linearity check of the CEMS has been performed and passed; or

(*2*) A probationary calibration error test of the CEMS is passed in accordance with §75.20(b)(3)(ii). Once the probationary calibration error test has been passed, the owner or operator shall perform the required linearity check in accordance with the conditional data validation provisions and within the 168 unit or stack operating hour time frame specified in §75.20(b)(3) (subject to the restrictions in paragraph (c)(3)(xii) of this section), and the term "quality assurance" shall apply instead of the term "recertification." However, in lieu of the provisions in §75.20(b)(3)(ix), the owner or operator shall follow the applicable provisions in paragraphs (c)(3)(xi) and (c)(3)(xii) of this section.

(F) A pre-season linearity check performed and passed in April satisfies the linearity check requirement for the second quarter.

(G) The third quarter linearity check requirement in paragraph (c)(3)(ii)(B) of this section is waived if:

(*1*) Due to infrequent unit operation, the 168 operating hour conditional data validation period associated with a pre-season linearity check extends into the third quarter; and

(*2*) A linearity check is performed and passed within that conditional data validation period.

(iii) For each flow monitoring system required by this subpart, except for flow monitors installed on non-load-based units that do not produce electrical or thermal output, flow-to-load ratio tests are required in the second and third calendar quarters, in accordance with section 2.2.5 of appendix B to this part. If the flow-to-load ratio test for the second calendar quarter is failed, the owner or operator shall follow the procedures in section 2.2.5(c)(8) of appendix B to this part. If the flow-to-load ratio test for the third calendar quarter is failed, data from the flow monitor shall be considered invalid at the beginning of the next ozone season unless, prior to May 1 of the next calendar year, the owner or operator has either successfully implemented Option 1 in section 2.2.5.1 of appendix B to this part or Option 2 in section 2.2.5.2 of appendix B to this part, or unless a flow RATA has been performed and passed in accordance with paragraph (c)(2)(ii) of this section.

(iv) For each differential pressure-type flow monitor used to meet the requirements of this subpart, quarterly leak checks are required in the second and third calendar quarters, in accordance with section 2.2.2 of appendix B to this part. For the second calendar quarter of the year, only the unit or stack operating hours in the months of May and June shall be used to determine whether the second calendar quarter is a QA operating quarter (as defined in §72.2 of this chapter). Data validation for quarterly flow monitor leak checks shall be done in accordance with section 2.2.3(g) of appendix B to this part. If the leak check for the third calendar quarter is failed and a subsequent leak check is not passed by the end of the ozone season, then data from the flow monitor shall be considered invalid at the beginning of the next ozone season unless a leak check is passed prior to May 1 of the next calendar year.

(v) A fuel flow-to-load ratio test in section 2.1.7 of appendix D to this part shall be performed in the second and third calendar quarters if, for a unit using a fuel flowmeter to determine heat input under this subpart, the owner or operator has elected to use the fuel flow-to-load ratio test to extend the deadline for the next fuel flowmeter accuracy test. Automatic deadline extensions may be claimed for the two calendar quarters outside the ozone season (the first and fourth calendar quarters), since a fuel flow-to-load ratio test is not required in those quarters. If a fuel flow-to-load ratio test is failed, follow the applicable procedures and data validation provisions in section 2.1.7.4 of appendix D to this part. If the fuel flow-to-load ratio test for the third calendar quarter is failed, data from the fuel flowmeter shall be considered invalid at the beginning of the next ozone season unless the requirements of section 2.1.7.4 of appendix D to this part have been fully met prior to May 1 of the next calendar year.

(vi)-(viii) [Reserved]

(ix) If, for any required CEMS, diagnostic linearity checks or RATAs other than those required by this section are performed during the ozone season, use the applicable data validation procedures in section 2.2.3 (for linearity checks) or 2.3.2 (for RATAs) of appendix B to this part.

(x) If any required CEMS is recertified within the ozone season, use the data validation provisions in §75.20(b)(3) and, if applicable, paragraphs (c)(3)(xi) and (c)(3)(xii) of this section.

(xi) If, at the end of the second quarter of any calendar year, a required quality assurance, diagnostic, or recertification test of a monitoring system has not been completed, and if data contained in the quarterly report are conditionally valid pending the results of test(s) to be completed in a subsequent quarter, the owner or operator shall indicate this by means of a suitable conditionally valid data flag in the electronic quarterly report for the second calendar quarter. The owner or operator shall resubmit the report for the second quarter if the required quality assurance, diagnostic, or recertification test is subsequently failed. In the resubmitted report, the owner or operator shall use the appropriate missing data routine in §§75.31 through §75.37 to replace with substitute data each hour of conditionally valid data that was invalidated by the failed quality assurance, diagnostic, or recertification test. Alternatively, if any required quality assurance, diagnostic, or recertification test is not completed by the end of the second calendar quarter but is completed no later than 30 days after the end of that quarter (*i.e.*, prior to the deadline for submitting the quarterly report under §75.73), the test data and results may be submitted with the second quarter report even though the test date(s) are from the third calendar quarter. In such instances, if the quality assurance, diagnostic, or recertification test(s) are passed in accordance with the conditional data validation provisions of §75.20(b)(3), conditionally valid data may be reported as quality-assured, in lieu of reporting a conditional data flag. If the tests are failed and if conditionally valid data are replaced, as appropriate, with substitute data, then neither the reporting of a conditional data flag nor resubmission is required.

(xii) If, at the end of the third quarter of any calendar year, a required quality assurance, diagnostic or recertification test of a monitoring system has not been completed, and if data contained in the quarterly report are conditionally valid pending the results of test(s) to be completed, the owner or operator shall do one of the following:

(A) If the results of the required tests are not available within 30 days of the end of the third calendar quarter and cannot be submitted with the quarterly report for the third calendar quarter, then the test results are considered to be missing and the owner or operator shall use the appropriate missing data routine in §§75.31 through §75.37 to replace with substitute data each hour of conditionally valid data in the third quarter report. In addition, if the data in the second quarterly report were flagged as conditionally valid at the end of the quarter, pending the results of the same missing tests, the owner or operator shall resubmit the report for the second quarter and shall use the appropriate missing data routine in §§75.31 through §75.37 to replace with substitute data each hour of conditionally valid data associated with the missing quality assurance, diagnostic, or recertification tests; or

(B) If the required quality assurance, diagnostic, or recertification tests are completed no later than 30 days after the end of the third calendar quarter, the test data and results may be submitted with the third quarter report even though the test date(s) are from the fourth calendar quarter. In this instance, if the required tests are passed in accordance with the conditional data validation provisions of §75.20(b)(3), all conditionally valid data associated with the tests shall be reported as quality-assured. If the tests are failed, the owner or operator shall use the appropriate missing data routine in §§75.31 through §75.37 to replace with substitute data each hour of conditionally valid data associated with the failed test(s). In addition, if the data in the second quarterly report were flagged as conditionally valid at the end of the quarter, pending the results of the same failed test(s), the owner or operator shall resubmit the report for the second quarter and shall use the appropriate missing data routine in §§75.31 through §75.37 to replace with substitute data each hour of conditionally valid data associated with the failed test(s).

(4) The owner or operator of a unit using the procedures in appendix D of this part to determine heat input rate is required to maintain fuel flowmeters only during the ozone season, except that for purposes of determining the deadline for the next periodic quality assurance test on the fuel flowmeter, the owner or operator shall include all fuel flowmeter QA operating quarters (as defined in §72.2) for the entire calendar year, not just fuel flowmeter QA operating quarters in the ozone season. For each calendar year, the owner or operator shall record, for each fuel flowmeter, the number of fuel flowmeter QA operating quarters. The owner or operator shall include all calendar quarters in the year when determining the deadline for visual inspection of the primary fuel flowmeter element, as specified in section 2.1.6(c) of appendix D to this part.

(5) The owner or operator of a unit using the procedures in appendix D of this part to determine heat input rate is only required to sample fuel for the purposes of determining density and GCV during the ozone season, except that:

(i) The owner or operator of a unit that performs sampling from the fuel storage tank upon delivery must sample the tank between the date and hour of the most recent delivery before the first date and hour that the unit operates in the ozone season and the first date and hour that the unit operates in the ozone season.

(ii) The owner or operator of a unit that performs sampling upon delivery from the delivery vehicle must ensure that all shipments received during the calendar year are sampled.

(iii) The owner or operator of a unit that performs sampling on each day the unit combusts fuel or that performs fuel sampling continuously must sample the fuel starting on the first day the unit operates during the ozone season. The owner or operator then shall use that sampled value for all hours of combustion during the first day of unit operation, continuing until the date and hour of the next sample.

(6) The owner or operator shall, in accordance with §75.73, record and report the hourly data required by this subpart and shall record and report the results of all required quality assurance tests, as follows:

(i) All hourly emission data for the period of time from May 1 through September 30 of each calendar year shall be recorded and reported. For missing data purposes, only the data recorded in the time period from May 1 through September 30 shall be considered quality-assured;

(ii) The results of all daily calibration error tests and flow monitor interference checks performed in the time period from May 1 through September 30 shall be recorded and reported;

(iii) For the time periods described in paragraphs (c)(2)(i)(C) and (c)(2)(ii)(E) of this section, hourly emission data and the results of all daily calibration error tests and flow monitor interference checks shall be recorded. The owner or operator may opt to report unit operating data, daily calibration error test and flow monitor interference check results, and hourly emission data in the time period from April 1 through April 30. However, only the data recorded in the time period from May 1 through September 30 shall be used for NO_X mass compliance determination;

(iv) The results of all required quality assurance tests (RATAs, linearity checks, flow-to-load ratio tests and leak checks) performed during the ozone season shall be reported in the appropriate ozone season quarterly report; and

(v) The results of RATAs (and any other quality assurance test(s) required under paragraph (c)(2) or (c)(3) of this section) which affect data validation for the current ozone season, but which were performed outside the ozone season (*i.e.*, between January 1 and April 30 of the current calendar year), shall be reported in the quarterly report for the second quarter of the current calendar year (or in the report for the third calendar quarter of the current calendar year, if the unit or stack does not operate in the second quarter).

(7) The owner or operator shall use only quality-assured data from within ozone seasons in the substitute data procedures under subpart D of this part and section 2.4.2 of appendix D to this part.

(i) The lookback periods (e.g., 2160 quality-assured monitor operating hours for a NO_X-diluent continuous emission monitoring system, a NO_X concentration monitoring system, or a flow monitoring system) used to calculate missing data must include only quality-assured data from periods within ozone seasons.

(ii) The applicable missing data procedures of §§75.31 through 75.37 shall be used, with one exception. When a fuel which has a significantly higher NO_X emission rate than any of the fuel(s) combusted in prior ozone seasons is combusted in the unit, and no quality-assured NO_X data have been recorded in the current, or any previous, ozone season while combusting the new fuel, the owner or operator shall substitute the maximum potential NO_X emission rate, as defined in §72.2 of this chapter, from a NO_X-diluent continuous emission monitoring system, or the maximum potential concentration of NO_X, as defined in section 2.1.2.1 of appendix A to this part, from a NO_X concentration monitoring system. The maximum potential value used shall be specific to the new fuel. The owner or operator shall substitute the maximum potential value for each hour of missing NO_X data until the first hour that quality-assured NO_X data are obtained while combusting the new fuel, and then shall resume use of the missing data routines in §§75.31 through 75.37; and

(iii) In order to apply the missing data routines described in §§75.31 through 75.37 on an ozone season-only basis, the procedures in those sections shall be modified as follows:

(A) The use of the initial missing data procedures in §75.31 shall commence with the first unit operating hour in the first ozone season for which emissions data are required to be reported under §75.64.

(B) In §75.31(a), the phrases “During the first 720 quality-assured monitor operating hours within the ozone season” and “during the first 2,160 quality-assured monitor operating hours within the ozone season” apply respectively instead of the phrases “During the first 720 quality-assured monitor operating hours” and “during the first 2,160 quality-assured monitor operating hours”.

(C) In §75.32(a), the phrases “the first 720 quality-assured monitor operating hours within the ozone season” and “the first 2,160 quality-assured monitor operating hours within the ozone season” apply, respectively, instead of the phrases “the first 720 quality-assured monitor operating hours” and “the first 2,160 quality-assured monitor operating hours”.

(D) In §75.32(a)(1), the phrase “Following initial certification, prior to completion of 3,672 unit (or stack) operating hours within the ozone season” applies instead of the phrase “Prior to completion of 8,760 unit (or stack) operating hours following initial certification”.

(E) In Equation 8, the phrase “Total unit operating hours within the ozone season” applies instead of the phrase “Total unit operating hours”.

(F) In §75.32(a)(2), the phrase “3,672 unit (or stack) operating hours within the ozone season” applies instead of the phrase “8,760 unit (or stack) operating hours”.

(G) In the numerator of Equation 9, the phrase “Total unit operating hours within the ozone season” applies instead of the phrase “Total unit operating hours”, and the phrase “3,672 unit operating hours within the ozone season” applies instead of the phrase “8,760 unit operating hours”. In the denominator of Equation 9, the number “3,672” applies instead of “8,760”.

(H) Use the following instead of the first three sentences in §75.32(a)(3): “When calculating percent monitor data availability using Equation 8 or 9, the owner or operator shall include all unit or stack operating hours within the ozone season, and all monitor operating hours within the ozone season for which quality-assured data were recorded by a certified primary monitor; a certified redundant or non-redundant backup monitor or a reference method for that unit; or by an approved alternative monitoring system under subpart E of this part. No hours from more than three years (26,280 clock hours) earlier shall be used in Equation 9. For a unit that has accumulated fewer than 3,672 ozone season operating hours in the previous three years, use the following: in the numerator of Equation 9 use ‘Total unit operating hours within the ozone season for which quality-assured data were recorded in the previous three years’; and in the denominator of Equation 9 use ‘Total unit operating hours within the ozone season, in the previous three years’”

(I) In §75.33(a), the phrases “the first 720 quality-assured monitor operating hours within the ozone season” and “the first 2,160 quality-assured monitor operating hours within the ozone season” apply, respectively, instead of the phrases “the first 720 quality-assured monitor operating hours” and “the first 2,160 quality-assured monitor operating hours”.

(J) Instead of the last sentence of §75.33(a), use “For the purposes of missing data substitution, the owner or operator of a unit shall use only quality-assured monitor operating hours of data that were recorded within the ozone season and no more than three years (26,280 clock hours) prior to the date and time of the missing data period.”

(K) In §§75.33(b), 75.33(c), 75.35, 75.36, and 75.37, the phrases “720 quality-assured monitor operating hours within the ozone season” and “2,160 quality-assured monitor operating hours within the ozone season” apply, respectively, instead of the phrases “720 quality-assured monitor operating hours” and “2,160 quality-assured monitor operating hours”.

(L) In §75.34(a)(3) and (a)(5), the phrases “720 quality-assured monitor operating hours within the ozone season” and “2160 quality-assured monitor operating hours within the ozone season” apply instead of “720 quality-assured monitor operating hours” and “2160 quality-assured monitor operating hours”, respectively.

(8) The owner or operator of a unit with NO_X add-on emission controls or a unit capable of combusting more than one fuel shall keep records during ozone season in a form suitable for inspection to demonstrate that the typical NO_X emission rate or NO_X concentration during the prior ozone season(s) included in the missing data lookback period is representative of the ozone season in which missing data are substituted and that use of the missing data procedures will not systematically underestimate NO_X mass emissions. These records shall include:

(i) For units that can combust more than one fuel, the fuel or fuels combusted each hour; and

(ii) For units with add-on emission controls, using the missing data options in §§75.34(a)(1) through 75.34(a)(5), the range of operating parameters for add-on emission controls (as defined in the quality assurance/quality control program for the unit required by section 1 in appendix B to this part) and information for verifying proper operation of the add-on emission controls during missing data periods, as described in §75.34(d).

(9) The designated representative shall certify with each quarterly report that NO_X emission rate values or NO_X concentration values substituted for missing data under subpart D of this part are calculated using only values from an ozone season, that substitute values measured during the prior ozone season(s) included in the missing data lookback period are representative of the ozone season in which missing data are substituted, and that NO_X emissions are not systematically underestimated.

(10) Units may qualify to use the low mass emissions excepted monitoring methodology in §75.19 on an ozone season basis. In order to be allowed to use this methodology, a unit may not emit more than 50 tons of NO_X per ozone season, as provided in §75.19(a)(1)(i)(A)(*3*). If any low mass emissions unit fails to provide a demonstration that its ozone season NO_X mass emissions are less than or equal to 50 tons, then the unit is disqualified from using the methodology. The owner or operator must install and certify any equipment needed to ensure that the unit is monitored using an acceptable methodology by December 31 of the following year.

(11) Units may qualify to use the optional NO_X mass emissions estimation protocol for gas-fired and oil-fired peaking units in appendix E to this part on an ozone season basis. In order to be allowed to use this methodology, the unit must meet the definition of “peaking unit” in §72.2 of this chapter, except that the words “year”, “calendar year” and “calendar years” in that definition shall be replaced by the words “ozone season”, “ozone season”, and “ozone seasons”, respectively. In addition, in the definition of the term “capacity factor” in §72.2 of this chapter, the word “annual” shall be replaced by the words “ozone season” and the number “8,760” shall be replaced by the number “3,672”.

[63 FR 57507, Oct. 27, 1998, as amended at 64 FR 28627, May 26, 1999; 67 FR 40446, 40447, June 12, 2002; 67 FR 57274, Sept. 9, 2002; 73 FR 4360, Jan. 24, 2008]

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§75.75 Additional ozone season calculation procedures for special circumstances.

(a) The owner or operator of a unit that is required to calculate ozone season heat input for purposes of providing data needed for determining allocations, shall do so by summing the unit's hourly heat input determined according to the procedures in this part for all hours in which the unit operated during the ozone season.

(b) The owner or operator of a unit that is required to determine ozone season NO_X emission rate (in lbs/mmBtu) shall do so by dividing ozone season NO_X mass emissions(in lbs) determined in accordance with this subpart, by heat input determined in accordance with paragraph (a) of this section.

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Appendix A to Part 75—Specifications and Test Procedures

1. Installation and Measurement Location

1.1 Gas Monitors

(a) Following the procedures in section 8.1.1 of Performance Specification 2 in appendix B to part 60 of this chapter, install the pollutant concentration monitor or monitoring system at a location where the pollutant concentration and emission rate measurements are directly representative of the total emissions from the affected unit. Select a representative measurement point or path for the monitor probe(s) (or for the path from the transmitter to the receiver) such that the SO_2, CO_2, O_2, or NO_X concentration monitoring system or NO_X-diluent CEMS (NO_X pollutant concentration monitor and diluent gas monitor) will pass the relative accuracy test (*see* section 6 of this appendix).

(b) It is recommended that monitor measurements be made at locations where the exhaust gas temperature is above the dew-point temperature. If the cause of failure to meet the relative accuracy tests is determined to be the measurement location, relocate the monitor probe(s).

1.1.1 Point Monitors

Locate the measurement point (1) within the centroidal area of the stack or duct cross section, or (2) no less than 1.0 meter from the stack or duct wall.

1.1.2 Path Monitors

Locate the measurement path (1) totally within the inner area bounded by a line 1.0 meter from the stack or duct wall, or (2) such that at least 70.0 percent of the path is within the inner 50.0 percent of the stack or duct cross-sectional area, or (3) such that the path is centrally located within any part of the centroidal area.

1.2 Flow Monitors

Install the flow monitor in a location that provides representative volumetric flow over all operating conditions. Such a location is one that provides an average velocity of the flue gas flow over the stack or duct cross section, provides a representative SO_2 emission rate (in lb/hr), and is representative of the pollutant concentration monitor location. Where the moisture content of the flue gas affects volumetric flow measurements, use the procedures in both Reference Methods 1 and 4 of appendix A to part 60 of this chapter to establish a proper location for the flow monitor. The EPA recommends (but does not require) performing a flow profile study following the procedures in 40 CFR part 60, appendix A, method, 1, sections 11.5 or 11.4 for each of the three operating or load levels indicated in section 6.5.2.1 of this appendix to determine the acceptability of the potential flow monitor location and to determine the number and location of flow sampling points required to obtain a representative flow value. The procedure in 40 CFR part 60, appendix A, Test Method 1, section 11.5 may be used even if the flow measurement location is greater than or equal to 2 equivalent stack or duct diameters downstream or greater than or equal to $\frac{1}{2}$ duct diameter upstream from a flow disturbance. If a flow profile study shows that cyclonic (or swirling) or stratified flow conditions exist at the potential flow monitor location that are likely to prevent the monitor from meeting the performance specifications of this part, then EPA recommends either (1) selecting another location where there is no cyclonic (or swirling) or stratified flow condition, or (2) eliminating the cyclonic (or swirling) or stratified flow condition by straightening the flow, e.g., by installing straightening vanes. EPA also recommends selecting flow monitor locations to minimize the effects of condensation, coating, erosion, or other conditions that could adversely affect flow monitor performance.

1.2.1 Acceptability of Monitor Location

The installation of a flow monitor is acceptable if either (1) the location satisfies the minimum siting criteria of method 1 in appendix A to part 60 of this chapter (i.e., the location is greater than or equal to eight stack or duct diameters downstream and two diameters upstream from a flow disturbance; or, if necessary, two stack or duct diameters downstream and one-half stack or duct diameter upstream from a flow disturbance), or (2) the results of a flow profile study, if performed, are acceptable (i.e., there are no cyclonic (or swirling) or stratified flow conditions), and the flow monitor also satisfies the performance specifications of this part. If the flow monitor is installed in a location that does not satisfy these physical criteria, but nevertheless the monitor achieves the performance specifications of this part, then the location is acceptable, notwithstanding the requirements of this section.

1.2.2 Alternative Monitoring Location

Whenever the owner or operator successfully demonstrates that modifications to the exhaust duct or stack (such as installation of straightening vanes, modifications of ductwork, and the like) are necessary for the flow monitor to meet the performance specifications, the Administrator may approve an interim alternative flow monitoring methodology and an extension to the required certification date for the flow monitor.

Where no location exists that satisfies the physical siting criteria in section 1.2.1, where the results of flow profile studies performed at two or more alternative flow monitor locations are unacceptable, or where installation of a flow monitor in either the stack or the ducts is demonstrated to be technically infeasible, the owner or operator may petition the Administrator for an alternative method for monitoring flow.

2. Equipment Specifications

2.1 Instrument Span and Range

In implementing sections 2.1.1 through 2.1.6 of this appendix, set the measurement range for each parameter (SO_2, NO_X, CO_2, O_2, or flow rate) high enough to prevent full-scale exceedances from occurring, yet low enough to ensure good measurement accuracy and to maintain a high signal-to-noise ratio. To meet these objectives, select the range such that the majority of the readings obtained during typical unit operation are kept, to the extent practicable, between 20.0 and 80.0 percent of the full-scale range of the instrument. These guidelines do not apply to: (1) SO_2 readings obtained during the combustion of very low sulfur fuel (as defined in §72.2 of this chapter); (2) SO_2 or NO_X readings recorded on the high measurement range, for units with SO_2 or NO_X emission controls and two span values, unless the emission controls are operated seasonally (for example, only during the ozone season); or (3) SO_2 or NO_X readings less than 20.0 percent of full-scale on the low measurement range for a dual span unit, provided that the maximum expected concentration (MEC), low-scale span value, and low-scale range settings have been determined according to sections 2.1.1.2, 2.1.1.4(a), (b), and (g) of this appendix (for SO_2), or according to sections 2.1.2.2, 2.1.2.4(a) and (f) of this appendix (for NO_X).

2.1.1 SO_2 Pollutant Concentration Monitors

Determine, as indicated in sections 2.1.1.1 through 2.1.1.5 of this appendix the span value(s) and range(s) for an SO_2 pollutant concentration monitor so that all potential and expected concentrations can be accurately measured and recorded. Note that if a unit exclusively combusts fuels that are very low sulfur fuels (as defined in §72.2 of this chapter), the SO_2 monitor span requirements in §75.11(e)(3)(iv) apply in lieu of the requirements of this section.

2.1.1.1 Maximum Potential Concentration

(a) Make an initial determination of the maximum potential concentration (MPC) of SO_2 by using Equation A-1a or A-1b. Base the MPC calculation on the maximum percent sulfur and the minimum gross calorific value (GCV) for the highest-sulfur fuel to be burned. The maximum sulfur content and minimum GCV shall be determined from all available fuel sampling and analysis data for that fuel from the previous 12 months (minimum), excluding clearly anomalous fuel sampling values. If both the fuel sulfur content and the GCV are routinely determined from each fuel sample, the owner or operator may, as an alternative to using the highest individual percent sulfur and lowest individual GCV values in the MPC calculation, pair the sulfur content and GCV values from each sample analysis and calculate the ratio of percent sulfur to GCV (*i.e.,* %S/GCV) for each pair of values. If this option is selected, the MPC shall be calculated using the highest %S/GCV ratio in Equation A-1a or A-1b. If the designated representative certifies that the highest-sulfur fuel is never burned alone in the unit during normal operation but is always blended or co-fired with other fuel(s), the MPC may be calculated using a best estimate of the highest sulfur content and lowest gross calorific value expected for the blend or fuel mixture and inserting these values into Equation A-1a or A-1b. Derive the best estimate of the highest percent sulfur and lowest GCV for a blend or fuel mixture from weighted-average values based upon the historical composition of the blend or mixture in the previous 12 (or more) months. If insufficient representative fuel sampling data are available to determine the maximum sulfur content and minimum GCV, use values from contract(s) for the fuel(s) that will be combusted by the unit in the MPC calculation.

$$MPC \text{ (or MEC)} = 11.32 \times 10^6 \left(\frac{\%S}{GCV}\right)\left(\frac{20.9 - \%O_{2w}}{20.9}\right) \quad (Eq.\ A\text{-}1a)$$

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or

$$MPC \text{ (or MEC)} = 66.93 \times 10^6 \left(\frac{\%S}{GCV}\right)\left(\frac{\%CO_{2w}}{100}\right) \quad (Eq.\ A\text{-}1b)$$

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Where,

MPC = Maximum potential concentration (ppm, wet basis). (To convert to dry basis, divide the MPC by 0.9.)

MEC = Maximum expected concentration (ppm, wet basis). (To convert to dry basis, divide the MEC by 0.9).

%S = Maximum sulfur content of fuel to be fired, wet basis, weight percent, as determined according to the applicable method in paragraph (c) of section 2.1.1.1.

$\%O_{2w}$ = Minimum oxygen concentration, percent wet basis, under typical operating conditions.

$\%CO_{2w}$ = Maximum carbon dioxide concentration, percent wet basis, under typical operating conditions.

GCV = Minimum gross calorific value of the fuel or blend to be combusted, based on historical fuel sampling and analysis data or, if applicable, based on the fuel contract specifications (Btu/lb). If based on fuel sampling and analysis, the GCV shall be determined according to the applicable method in paragraph (c) of section 2.1.1.1.

11.32×10^6 = Oxygen-based conversion factor in Btu/lb (ppm)/%.

66.93×10^6 = Carbon dioxide-based conversion factor in Btu/lb (ppm)/%.

NOTE: All percent values to be inserted in the equations of this section are to be expressed as a percentage, not a fractional value (e.g., 3, not .03).

(b) Alternatively, if a certified SO_2 CEMS is already installed, the owner or operator may make the initial MPC determination based upon quality-assured historical data recorded by the CEMS. For the purposes of this section, 2.1.1.1, a “certified” CEMS means a CEM system that has met the applicable certification requirements of either: This part, or part 60 of this chapter, or a State CEM program, or the source operating permit. If this option is chosen, the MPC shall be the maximum SO_2 concentration observed during the previous 720 (or more) quality-assured monitor operating hours when combusting the highest-sulfur fuel (or highest-sulfur blend if fuels are always blended or co-fired) that is to be combusted in the unit or units monitored by the SO_2 monitor. For units with SO_2 emission controls, the certified SO_2 monitor used to determine the MPC must be located at or before the control device inlet. Report the MPC and the method of determination in the monitoring plan required under §75.53. Note that the initial MPC value is subject to periodic review under section 2.1.1.5 of this appendix. If an MPC value is found to be either inappropriately high or low, the MPC shall be adjusted in accordance with section 2.1.1.5, and corresponding span and range adjustments shall be made, if necessary.

(c) When performing fuel sampling to determine the MPC, use ASTM Methods: ASTM D129-00, ASTM D240-00, ASTM D1552-01, ASTM D2622-98, ASTM D3176-89 (Reapproved 2002), ASTM D3177-02 (Reapproved 2007), ASTM D4239-02, ASTM D4294-98, ASTM D5865-01a, or ASTM D5865-10 (all incorporated by reference under §75.6).

2.1.1.2 Maximum Expected Concentration

(a) Make an initial determination of the maximum expected concentration (MEC) of SO_2 whenever: (a) SO_2 emission controls are used; or (b) both high-sulfur and low-sulfur fuels (e.g., high-sulfur coal and low-sulfur coal or different grades of fuel oil) or high-sulfur and low-sulfur fuel blends are combusted as primary or backup fuels in a unit without SO_2 emission controls. For units with SO_2 emission controls, use Equation A-2 to make the initial MEC determination. When high-sulfur and low-sulfur fuels or blends are burned as primary or backup fuels in a unit without SO_2 controls, use Equation A-1a or A-1b to calculate the initial MEC value for each fuel or blend, except for: (1) the highest-sulfur fuel or blend (for which the MPC was previously calculated in section 2.1.1.1 of this appendix); (2) fuels or blends that are very low sulfur fuels (as defined in §72.2 of this chapter); or (3) fuels or blends that are used only for unit startup. Each initial MEC value shall be documented in the monitoring plan required under §75.53. Note that each initial MEC value is subject to periodic review under section 2.1.1.5 of this appendix. If an MEC value is found to be either inappropriately high or low, the MEC shall be adjusted in accordance with section 2.1.1.5, and corresponding span and range adjustments shall be made, if necessary.

(b) For each MEC determination, substitute into Equation A-1a or A-1b the highest sulfur content and minimum GCV value for that fuel or blend, based upon all available fuel sampling and analysis results from the previous 12 months (or more), or, if fuel sampling data are unavailable, based upon fuel contract(s).

(c) Alternatively, if a certified SO_2 CEMS is already installed, the owner or operator may make the initial MEC determination(s) based upon historical monitoring data. For the purposes of this section, 2.1.1.2, a "certified" CEMS means a CEM system that has met the applicable certification requirements of either: This part, or part 60 of this chapter, or a State CEM program, or the source operating permit. If this option is chosen for a unit with SO_2 emission controls, the MEC shall be the maximum SO_2 concentration measured downstream of the control device outlet by the CEMS over the previous 720 (or more) quality-assured monitor operating hours with the unit and the control device both operating normally. For units that burn high- and low-sulfur fuels or blends as primary and backup fuels and have no SO_2 emission controls, the MEC for each fuel shall be the maximum SO_2 concentration measured by the CEMS over the previous 720 (or more) quality-assured monitor operating hours in which that fuel or blend was the only fuel being burned in the unit.

$$MEC = MPC\left(\frac{100 - RE}{100}\right) \qquad (Eq.\ A\text{-}2)$$

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Where:

MEC = Maximum expected concentration (ppm).

MPC = Maximum potential concentration (ppm), as determined by Eq. A-1a or A-1b in section 2.1.1.1 of this appendix.

RE = Expected average design removal efficiency of control equipment (%).

2.1.1.3 Span Value(s) and Range(s)

Determine the high span value and the high full-scale range of the SO_2 monitor as follows. (Note: For purposes of this part, the high span and range refer, respectively, either to the span and range of a single span unit or to the high span and range of a dual span unit.) The high span value shall be obtained by multiplying the MPC by a factor no less than 1.00 and no greater than 1.25. Round the span value upward to the next highest multiple of 100 ppm. If the SO_2 span concentration is ≤500 ppm, the span value may either be rounded upward to the next highest multiple of 10 ppm, or to the next highest multiple of 100 ppm. The high span value shall be used to determine concentrations of the calibration gases required for daily calibration error checks and linearity tests. Select the full-scale range of the instrument to be consistent with section 2.1 of this appendix and to be greater than or equal to the span value. Report the full-scale range setting and calculations of the MPC and span in the monitoring plan for the unit. Note that for certain applications, a second (low) SO_2 span and range may be required (see section 2.1.1.4 of this appendix). If an existing State, local, or federal requirement for span of an SO_2 pollutant concentration monitor requires or allows the use of a span value lower than that required by this section or by section 2.1.1.4 of this appendix, the State, local, or federal span value may be used if a satisfactory explanation is included in the monitoring plan, unless span and/or range adjustments become necessary in accordance with section 2.1.1.5 of this appendix. Span values higher than those required by either this section or section 2.1.1.4 of this appendix must be approved by the Administrator.

2.1.1.4 Dual Span and Range Requirements

For most units, the high span value based on the MPC, as determined under section 2.1.1.3 of this appendix will suffice to measure and record SO_2 concentrations (unless span and/or range adjustments become necessary in accordance with section 2.1.1.5 of this appendix). In some instances, however, a second (low) span value based on the MEC may be required to ensure accurate measurement of all possible or expected SO_2 concentrations. To determine whether two SO_2 span values are required, proceed as follows:

(a) For units with SO_2 emission controls, compare the MEC from section 2.1.1.2 of this appendix to the high full-scale range value from section 2.1.1.3 of this appendix. If the MEC is ≥20.0 percent of the high range value, then the high span value and range determined under section 2.1.1.3 of this appendix are sufficient. If the MEC is <20.0 percent of the high range value, then a second (low) span value is required.

(b) For units that combust high- and low-sulfur primary and backup fuels (or blends) and have no SO_2 controls, compare the high range value from section 2.1.1.3 of this appendix (for the highest-sulfur fuel or blend) to the MEC value for each of the other fuels or blends, as determined under section 2.1.1.2 of this appendix. If all of the MEC values are ≥20.0 percent of the high range value, the high span and range determined under section 2.1.1.3 of this appendix are sufficient, regardless of which fuel or blend is burned in the unit. If any MEC value is <20.0 percent of the high range value, then a second (low) span value must be used when that fuel or blend is combusted.

(c) When two SO_2 spans are required, the owner or operator may either use a single SO_2 analyzer with a dual range (i.e., low- and high-scales) or two separate SO_2 analyzers connected to a common sample probe and sample interface. Alternatively, if RATAs are performed and passed on both measurement ranges, the owner or operator may use two separate SO_2 analyzers connected to separate probes and sample interfaces. For units with SO_2 emission controls, the owner or operator may use a low range analyzer and a default high range value, as described in paragraph (f) of this section, in lieu of maintaining and quality assuring a high-scale range. Other monitor configurations are subject to the approval of the Administrator.

(d) The owner or operator shall designate the monitoring systems and components in the monitoring plan under §75.53 as follows: when a single probe and sample interface are used, either designate the low and high monitor ranges as separate SO_2 components of a single, primary SO_2 monitoring system; designate the low and high monitor ranges as the SO_2 components of two separate, primary SO_2 monitoring systems; designate the normal monitor range as a primary monitoring system and the other monitor range as a non-redundant backup monitoring system; or, when a single, dual-range SO_2 analyzer is used, designate the low and high ranges as a single SO_2 component of a primary SO_2 monitoring system (if this option is selected, use a special dual-range component type code, as specified by the Administrator, to satisfy the requirements of §75.53(e)(1)(iv)(D)). When two SO_2 analyzers are connected to separate probes and sample interfaces, designate the analyzers as the SO_2 components of two separate, primary SO_2 monitoring systems. For units with SO_2 controls, if the default high range value is used, designate the low range analyzer as the SO_2 component of a primary SO_2 monitoring system. Do not designate the default high range as a monitoring system or component. Other component and system designations are subject to approval by the Administrator. Note that the component and system designations for redundant backup monitoring systems shall be the same as for primary monitoring systems.

(e) Each monitoring system designated as primary or redundant backup shall meet the initial certification and quality assurance requirements for primary monitoring systems in §75.20(c) or §75.20(d)(1), as applicable, and appendices A and B to this part, with one exception: relative accuracy test audits (RATAs) are required only on the normal range (for units with SO_2 emission controls, the low range is considered normal). Each monitoring system designated as a non-redundant backup shall meet the applicable quality assurance requirements in §75.20(d)(2).

(f) For dual span units with SO_2 emission controls, the owner or operator may, as an alternative to maintaining and quality assuring a high monitor range, use a default high range value. If this option is chosen, the owner or operator shall report a default SO_2 concentration of 200 percent of the MPC for each unit operating hour in which the full-scale of the low range SO_2 analyzer is exceeded.

(g) The high span value and range shall be determined in accordance with section 2.1.1.3 of this appendix. The low span value shall be obtained by multiplying the MEC by a factor no less than 1.00 and no greater than 1.25, and rounding the result upward to the next highest multiple of 10 ppm (or 100 ppm, as appropriate). For units that burn high- and low-sulfur primary and backup fuels or blends and have no SO_2 emission controls, select, as the basis for calculating the appropriate low span value and range, the fuel-specific MEC value closest to 20.0 percent of the high full-scale range value (from paragraph (b) of this section). The low range must be greater than or equal to the low span value, and the required calibration gases must be selected based on the low span value. However, if the default high range option in paragraph (f) of this section is selected, the full-scale of the low measurement range shall not exceed five times the MEC value (where the MEC is rounded upward to the next highest multiple of 10 ppm). For units with two SO_2 spans, use the low range whenever the SO_2 concentrations are expected to be consistently below 20.0 percent of the high full-scale range value, i.e., when the MEC of the fuel or blend being combusted is less than 20.0 percent of the high full-scale range value. When the full-scale of the low range is exceeded, the high range shall be used to measure and record the SO_2 concentrations; or, if applicable, the default high range value in paragraph (f) of this section shall be reported for each hour of the full-scale exceedance.

2.1.1.5 Adjustment of Span and Range

For each affected unit or common stack, the owner or operator shall make a periodic evaluation of the MPC, MEC, span, and range values for each SO_2 monitor (at a minimum, an annual evaluation is required) and shall make any necessary span and range adjustments, with corresponding monitoring plan updates, as described in paragraphs (a), (b), and (c) of this section. Span and range adjustments may be required, for example, as a result of changes in the fuel supply, changes in the manner of operation of the unit, or installation or removal of emission controls. In implementing the provisions in paragraphs (a) and (b) of this section, SO_2 data recorded during short-term, non-representative process operating conditions (e.g., a trial burn of a different type of fuel) shall be excluded from consideration. The owner or operator shall keep the results of the most recent span and range evaluation on-site, in a format suitable for inspection. Make each required span or range adjustment no later than 45 days after the end of the quarter in which the need to adjust the span or range is identified, except that up to 90 days after the end of that quarter may be taken to implement a span adjustment if the calibration gases currently being used for daily calibration error tests and linearity checks are unsuitable for use with the new span value.

(a) If the fuel supply, the composition of the fuel blend(s), the emission controls, or the manner of operation change such that the maximum expected or potential concentration changes significantly, adjust the span and range setting to assure the continued accuracy of the monitoring system. A "significant" change in the MPC or MEC means that the guidelines in section 2.1 of this appendix can no longer be met, as determined by either a periodic evaluation by the owner or operator or from the results of an audit by the Administrator. The owner or operator should evaluate whether any planned changes in operation of the unit may affect the concentration of emissions being emitted from the unit or stack and should plan any necessary span and range changes needed to account for these changes, so that they are made in as timely a manner as practicable to coordinate with the operational changes. Determine the adjusted span(s) using the procedures in sections 2.1.1.3 and 2.1.1.4 of this appendix (as applicable). Select the full-scale range(s) of the instrument to be greater than or equal to the new span value(s) and to be consistent with the guidelines of section 2.1 of this appendix.

(b) Whenever a full-scale range is exceeded during a quarter and the exceedance is not caused by a monitor out-of-control period, proceed as follows:

(1) For exceedances of the high range, report 200.0 percent of the current full-scale range as the hourly SO_2 concentration for each hour of the full-scale exceedance and make appropriate adjustments to the MPC, span, and range to prevent future full-scale exceedances.

(2) For units with two SO_2 spans and ranges, if the low range is exceeded, no further action is required, provided that the high range is available and its most recent calibration error test and linearity check have not expired. However, if either of these quality assurance tests has expired and the high range is not able to provide quality assured data at the time of the low range exceedance or at any time during the continuation of the exceedance, report the MPC as the SO_2 concentration until the readings return to the low range or until the high range is able to provide quality assured data (unless the reason that the high-scale range is not able to provide quality assured data is because the high-scale range has been exceeded; if the high-scale range is exceeded follow the procedures in paragraph (b)(1) of this section).

(c) Whenever changes are made to the MPC, MEC, full-scale range, or span value of the SO_2 monitor, as described in paragraphs (a) or (b) of this section, record and report (as applicable) the new full-scale range setting, the new MPC or MEC and calculations of the adjusted span value in an updated monitoring plan. The monitoring plan update shall be made in the quarter in which the changes become effective. In addition, record and report the adjusted span as part of the records for the daily calibration error test and linearity check specified by appendix B to this part. Whenever the span value is adjusted, use calibration gas concentrations that meet the requirements of section 5.1 of this appendix, based on the adjusted span value. When a span adjustment is so significant that the calibration gases currently being used for daily calibration error tests and linearity checks are unsuitable for use with the new span value, then a diagnostic linearity test using the new calibration gases must be performed and passed. Use the data validation procedures in §75.20(b)(3), beginning with the hour in which the span is changed.

2.1.2 NO_X Pollutant Concentration Monitors

Determine, as indicated in sections 2.1.2.1 through 2.1.2.5 of this appendix, the span and range value(s) for the NO_X pollutant concentration monitor so that all expected NO_X concentrations can be determined and recorded accurately.

2.1.2.1 Maximum Potential Concentration

(a) The maximum potential concentration (MPC) of NO_X for each affected unit shall be based upon whichever fuel or blend combusted in the unit produces the highest level of NO_X emissions. For the purposes of this section, 2.1.2.1, and section 2.1.2.2 of this appendix, a "blend" means a frequently-used fuel mixture having a consistent composition (e.g., an oil and gas mixture where the relative proportions of the two fuels vary by no more than 10%, on average). Make an initial determination of the MPC using the appropriate option as follows:

Option 1: Use 800 ppm for coal-fired and 400 ppm for oil- or gas-fired units as the maximum potential concentration of NO_X (if an MPC of 1600 ppm for coal-fired units or 480 ppm for oil- or gas-fired units was previously selected under this section, that value may still be used, provided that the guidelines of section 2.1 of this appendix are met); For cement kilns, use 2000 ppm as the MPC. For process heaters, use 200 ppm if the unit burns only gaseous fuel and 500 ppm if the unit burns oil;

Option 2: Use the specific values based on boiler type and fuel combusted, listed in Table 2-1 or Table 2-2; For a new gas-fired or oil-fired combustion turbine, if a default MPC value of 50 ppm was previously selected from Table 2-2, that value may be used until March 31, 2003;

Option 3: Use NO_X emission test results;

Option 4: Use historical CEM data over the previous 720 (or more) unit operating hours when combusting the fuel or blend with the highest NO_X emission rate; or

Option 5: If a reliable estimate of the uncontrolled NO_X emissions from the unit is available from the manufacturer, the estimated value may be used.

(b) For the purpose of providing substitute data during NO_X missing data periods in accordance with §§75.31 and 75.33 and as required elsewhere under this part, the owner or operator shall also calculate the maximum potential NO_X emission rate (MER), in lb/mmBtu, by substituting the MPC for NO_X in conjunction with the minimum expected CO_2 or maximum O_2 concentration (under all unit operating conditions except for unit startup, shutdown, and upsets) and the appropriate F-factor into the applicable equation in appendix F to this part. The diluent cap value of 5.0 percent CO_2 (or 14.0 percent O_2) for boilers or 1.0 percent CO_2 (or 19.0 percent O_2) for combustion turbines may be used in the NO_X MER calculation. As a second alternative, when the NO_X MPC is determined from emission test results or from historical CEM data, as described in paragraphs (a), (d) and (e) of this section, quality-assured diluent gas (i.e., O_2 or CO_2) data recorded concurrently with the MPC may be used to calculate the MER.

(c) Report the method of determining the initial MPC and the calculation of the maximum potential NO_X emission rate in the monitoring plan for the unit. Note that whichever MPC option in paragraph 2.1.2.1(a) of this appendix is selected, the initial MPC value is subject to periodic review under section 2.1.2.5 of this appendix. If an MPC value is found to be either inappropriately high or low, the MPC shall be adjusted in accordance with section 2.1.2.5, and corresponding span and range adjustments shall be made, if necessary.

(d) For units with add-on NO_X controls (whether or not the unit is equipped with low-NO_X burner technology), or for units equipped with dry low-NO_X (DLN) technology, NO_X emission testing may only be used to determine the MPC if testing can be performed either upstream of the add-on controls or during a time or season when the add-on controls are not in operation or when the DLN controls are not in the premixed (low-NO_X) mode. If NO_X emission testing is performed, use the following guidelines. Use Method 7E from appendix A to part 60 of this chapter to measure total NO_X concentration. (Note: Method 20 from appendix A to part 60 may be used for gas turbines, instead of Method 7E.) Operate the unit, or group of units sharing a common stack, at the minimum safe and stable load, the normal load, and the maximum load. If the normal load and maximum load are identical, an intermediate level need not be tested. Operate at the highest excess O_2 level expected under normal operating conditions. Make at least three runs of 20 minutes (minimum) duration with three traverse points per run at each operating condition. Select the highest point NO_X concentration from all test runs as the MPC for NO_X.

(e) If historical CEM data are used to determine the MPC, the data must, for uncontrolled units or units equipped with low-NO_X burner technology and no other NO_X controls, represent a minimum of 720 quality-assured monitor operating hours from the NO_X component of a certified monitoring system, obtained under various operating conditions including the minimum safe and stable load, normal load (including periods of high excess air at normal load), and maximum load. For the purposes of this section, 2.1.2.1, a “certified” CEMS means a CEM system that has met the applicable certification requirements of either: this part, or part 60 of this chapter, or a State CEM program, or the source operating permit. For a unit with add-on NO_X controls (whether or not the unit is equipped with low-NO_X burner technology), or for a unit equipped with dry low-NO_X (DLN) technology, historical CEM data may only be used to determine the MPC if the 720 quality-assured monitor operating hours of CEM data are collected upstream of the add-on controls or if the 720 hours of data include periods when the add-on controls are not in operation or when the DLN controls are not in the premixed (low-NO_X mode). For units that do not produce electrical or thermal output, the data must represent the full range of normal process operation. The highest hourly NO_X concentration in ppm shall be the MPC.

Table 2-1—Maximum Potential Concentration for NO_X—Coal-Fired Units

Unit type	Maximum potential concentration for NO_X (ppm)
Tangentially-fired dry bottom and fluidized bed	460
Wall-fired dry bottom, turbo-fired dry bottom, stokers	675
Roof-fired (vertically-fired) dry bottom, cell burners, arch-fired	975
Cyclone, wall-fired wet bottom, wet bottom turbo-fired	1200
Others	([1])

[1]As approved by the Administrator.

TABLE 2-2. -- MAXIMUM POTENTIAL CONCENTRATION FOR NO_X -- Gas- And Oil-Fired Units

Unit type	Maximum potential concentration for NO_x (ppm)
Tangentially-fired dry bottom	380
Wall-fired dry bottom	600
Roof-fired (vertically-fired) dry bottom, arch-fired	550
Existing combustion turbine	200
New combustion turbine, permitted to fire either oil or natural gas	200
New combustion turbine, permitted to fire only natural gas	150
Others	(1)

[1] As approved by the Administrator

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2.1.2.2 Maximum Expected Concentration

(a) Make an initial determination of the maximum expected concentration (MEC) of NO_X during normal operation for affected units with add-on NO_X controls of any kind (*e.g.,* steam injection, water injection, SCR, or SNCR) and for turbines that use dry low-NO_X technology. Determine a separate MEC value for each type of fuel (or blend) combusted in the unit, except for fuels that are only used for unit startup and/or flame stabilization. Calculate the MEC of NO_X using Equation A-2, if applicable, inserting the maximum potential concentration, as determined using the procedures in section 2.1.2.1 of this appendix. Where Equation A-2 is not applicable, set the MEC either by: (1) measuring the NO_X concentration using the testing procedures in this section; (2) using historical CEM data over the previous 720 (or more) quality-assured monitor operating hours; or (3) if the unit has add-on NO_X controls or uses dry low NO_X technology, and has a federally-enforceable permit limit for NO_X concentration, the permit limit may be used as the MEC. Include in the monitoring plan for the unit each MEC value and the method by which the MEC was determined. Note that each initial MEC value is subject to periodic review under section 2.1.2.5 of this appendix. If an MEC value is found to be either inappropriately high or low, the MEC shall be adjusted in accordance with section 2.1.2.5, and corresponding span and range adjustments shall be made, if necessary.

(b) If NO_X emission testing is used to determine the MEC value(s), the MEC for each type of fuel (or blend) shall be based upon testing at minimum load, normal load, and maximum load. At least three tests of 20 minutes (minimum) duration, using at least three traverse points, shall be performed at each load, using Method 7E from appendix A to part 60 of this chapter (Note: Method 20 from appendix A to part 60 may be used for gas turbines instead of Method 7E). The test must be performed at a time when all NO_X control devices and methods used to reduce NO_X emissions (if applicable) are operating properly. The testing shall be conducted downstream of all NO_X controls. The highest point NO_X concentration (e.g., the highest one-minute average) recorded during any of the test runs shall be the MEC.

(c)If historical CEM data are used to determine the MEC value(s), the MEC for each type of fuel shall be based upon 720 (or more) hours of quality-assured data from the NO_X component of a certified monitoring system representing the entire load range under stable operating conditions. For the purposes of this section, 2.1.2.2, a “certified” CEMS means a CEM system that has met the applicable certification requirements of either: this part, or part 60 of this chapter, or a State CEM program, or the source operating permit. The data base for the MEC shall not include any CEM data recorded during unit startup, shutdown, or malfunction or (for units with add-on NO_X controls or turbines using dry low NO_X technology) during any NO_X control device malfunctions or outages. All NO_X control devices and methods used to reduce NO_X emissions (if applicable) must be operating properly during each hour. The CEM data shall be collected downstream of all NO_X controls. For each type of fuel, the highest of the 720 (or more) quality-assured hourly average NO_X concentrations recorded by the CEMS shall be the MEC.

2.1.2.3 Span Value(s) and Range(s)

(a) Determine the high span value of the NO_X monitor as follows. The high span value shall be obtained by multiplying the MPC by a factor no less than 1.00 and no greater than 1.25. Round the span value upward to the next highest multiple of 100 ppm. If the NO_X span concentration is ≤500 ppm, the span value may either be rounded upward to the next highest multiple of 10 ppm, or to the next highest multiple of 100 ppm. The high span value shall be used to determine the concentrations of the calibration gases required for daily calibration error checks and linearity tests. Note that for certain applications, a second (low) NO_X span and range may be required (see section 2.1.2.4 of this appendix).

(b) If an existing State, local, or federal requirement for span of a NO_X pollutant concentration monitor requires or allows the use of a span value lower than that required by this section or by section 2.1.2.4 of this appendix, the State, local, or federal span value may be used, where a satisfactory explanation is included in the monitoring plan, unless span and/or range adjustments become necessary in accordance with section 2.1.2.5 of this appendix. Span values higher than required by this section or by section 2.1.2.4 of this appendix must be approved by the Administrator.

(c) Select the full-scale range of the instrument to be consistent with section 2.1 of this appendix and to be greater than or equal to the high span value. Include the full-scale range setting and calculations of the MPC and span in the monitoring plan for the unit.

2.1.2.4 Dual Span and Range Requirements

For most units, the high span value based on the MPC, as determined under section 2.1.2.3 of this appendix will suffice to measure and record NO_X concentrations (unless span and/or range adjustments must be made in accordance with section 2.1.2.5 of this appendix). In some instances, however, a second (low) span value based on the MEC may be required to ensure accurate measurement of all expected and potential NO_X concentrations. To determine whether two NO_X spans are required, proceed as follows:

(a) Compare the MEC value(s) determined in section 2.1.2.2 of this appendix to the high full-scale range value determined in section 2.1.2.3 of this appendix. If the MEC values for all fuels (or blends) are ≥20.0 percent of the high range value, the high span and range values determined under section 2.1.2.3 of this appendix are sufficient, irrespective of which fuel or blend is combusted in the unit. If any of the MEC values is <20.0 percent of the high range value, two spans (low and high) are required, one based on the MPC and the other based on the MEC.

(b) When two NO_X spans are required, the owner or operator may either use a single NO_X analyzer with a dual range (low- and high-scales) or two separate NO_X analyzers connected to a common sample probe and sample interface. Two separate NO_X analyzers connected to separate probes and sample interfaces may be used if RATAs are passed on both ranges. For units with add-on NO_X emission controls (e.g., steam injection, water injection, SCR, or SNCR) or units equipped with dry low-NO_X technology, the owner or operator may use a low range analyzer and a “default high range value,” as described in paragraph 2.1.2.4(e) of this section, in lieu of maintaining and quality assuring a high-scale range. Other monitor configurations are subject to the approval of the Administrator.

(c) The owner or operator shall designate the monitoring systems and components in the monitoring plan under §75.53 as follows: when a single probe and sample interface are used, either designate the low and high ranges as separate NO_X components of a single, primary NO_X monitoring system; designate the low and high ranges as the NO_X components of two separate, primary NO_X monitoring systems; designate the normal range as a primary monitoring system and the other range as a non-redundant backup monitoring system; or, when a single, dual-range NO_X analyzer is used, designate the low and high ranges as a single NO_X component of a primary NO_X monitoring system (if this option is selected, use a special dual-range component type code, as specified by the Administrator, to satisfy the requirements of §75.53(e)(1)(iv)(D)). When two NO_X analyzers are connected to separate probes and sample interfaces, designate the analyzers as the NO_X components of two separate, primary NO_X monitoring systems. For units with add-on NO_X controls or units equipped with dry low-NO_X technology, if the default high range value is used, designate the low range analyzer as the NO_X component of the primary NO_X monitoring system. Do not designate the default high range as a monitoring system or component. Other component and system designations are subject to approval by the Administrator. Note that the component and system designations for redundant backup monitoring systems shall be the same as for primary monitoring systems.

(d) Each monitoring system designated as primary or redundant backup shall meet the initial certification and quality assurance requirements in §75.20(c) (for primary monitoring systems), in §75.20(d)(1) (for redundant backup monitoring systems) and appendices A and B to this part, with one exception: relative accuracy test audits (RATAs) are required only on the normal range (for dual span units with add-on NO_X emission controls, the low range is considered normal). Each monitoring system designated as non-redundant backup shall meet the applicable quality assurance requirements in §75.20(d)(2).

(e) For dual span units with add-on NO_X emission controls (e.g., steam injection, water injection, SCR, or SNCR), or, for units that use dry low NO_X technology, the owner or operator may, as an alternative to maintaining and quality assuring a high monitor range, use a default high range value. If this option is chosen, the owner or operator shall report a default value of 200.0 percent of the MPC for each unit operating hour in which the full-scale of the low range NO_X analyzer is exceeded.

(f) The high span and range shall be determined in accordance with section 2.1.2.3 of this appendix. The low span value shall be 100.0 to 125.0 percent of the MEC, rounded up to the next highest multiple of 10 ppm (or 100 ppm, if appropriate). If more than one MEC value (as determined in section 2.1.2.2 of this appendix) is <20.0 percent of the high full-scale range value, the low span value shall be based upon whichever MEC value is closest to 20.0 percent of the high range value. The low range must be greater than or equal to the low span value, and the required calibration gases for the low range must be selected based on the low span value. However, if the default high range option in paragraph (e) of this section is selected, the full-scale of the low measurement range shall not exceed five times the MEC value (where the MEC is rounded upward to the next highest multiple of 10 ppm). For units with two NO_X spans, use the low range whenever NO_X concentrations are expected to be consistently <20.0 percent of the high range value, i.e., when the MEC of the fuel being combusted is <20.0 percent of the high range value. When the full-scale of the low range is exceeded, the high range shall be used to measure and record the NO_X

concentrations; or, if applicable, the default high range value in paragraph (e) of this section shall be reported for each hour of the full-scale exceedance.

2.1.2.5 Adjustment of Span and Range

For each affected unit or common stack, the owner or operator shall make a periodic evaluation of the MPC, MEC, span, and range values for each NO_X monitor (at a minimum, an annual evaluation is required) and shall make any necessary span and range adjustments, with corresponding monitoring plan updates, as described in paragraphs (a), (b), and (c) of this section. Span and range adjustments may be required, for example, as a result of changes in the fuel supply, changes in the manner of operation of the unit, or installation or removal of emission controls. In implementing the provisions in paragraphs (a) and (b) of this section, note that NO_X data recorded during short-term, non-representative operating conditions (e.g., a trial burn of a different type of fuel) shall be excluded from consideration. The owner or operator shall keep the results of the most recent span and range evaluation on-site, in a format suitable for inspection. Make each required span or range adjustment no later than 45 days after the end of the quarter in which the need to adjust the span or range is identified, except that up to 90 days after the end of that quarter may be taken to implement a span adjustment if the calibration gases currently being used for daily calibration error tests and linearity checks are unsuitable for use with the new span value.

(a) If the fuel supply, emission controls, or other process parameters change such that the maximum expected concentration or the maximum potential concentration changes significantly, adjust the NO_X pollutant concentration span(s) and (if necessary) monitor range(s) to assure the continued accuracy of the monitoring system. A “significant” change in the MPC or MEC means that the guidelines in section 2.1 of this appendix can no longer be met, as determined by either a periodic evaluation by the owner or operator or from the results of an audit by the Administrator. The owner or operator should evaluate whether any planned changes in operation of the unit or stack may affect the concentration of emissions being emitted from the unit and should plan any necessary span and range changes needed to account for these changes, so that they are made in as timely a manner as practicable to coordinate with the operational changes. An example of a change that may require a span and range adjustment is the installation of low-NO_X burner technology on a previously uncontrolled unit. Determine the adjusted span(s) using the procedures in section 2.1.2.3 or 2.1.2.4 of this appendix (as applicable). Select the full-scale range(s) of the instrument to be greater than or equal to the adjusted span value(s) and to be consistent with the guidelines of section 2.1 of this appendix.

(b) Whenever a full-scale range is exceeded during a quarter and the exceedance is not caused by a monitor out-of-control period, proceed as follows:

(1) For exceedances of the high range, report 200.0 percent of the current full-scale range as the hourly NO_X concentration for each hour of the full-scale exceedance and make appropriate adjustments to the MPC, span, and range to prevent future full-scale exceedances.

(2) For units with two NO_X spans and ranges, if the low range is exceeded, no further action is required, provided that the high range is available and its most recent calibration error test and linearity check have not expired. However, if either of these quality assurance tests has expired and the high range is not able to provide quality assured data at the time of the low range exceedance or at any time during the continuation of the exceedance, report the MPC as the NO_X concentration until the readings return to the low range or until the high range is able to provide quality assured data (unless the reason that the high-scale range is not able to provide quality assured data is because the high-scale range has been exceeded; if the high-scale range is exceeded, follow the procedures in paragraph (b)(1) of this section).

(c) Whenever changes are made to the MPC, MEC, full-scale range, or span value of the NO_X monitor as described in paragraphs (a) and (b) of this section, record and report (as applicable) the new full-scale range setting, the new MPC or MEC, maximum potential NO_X emission rate, and the adjusted span value in an updated monitoring plan for the unit. The monitoring plan update shall be made in the quarter in which the changes become effective. In addition, record and report the adjusted span as part of the records for the daily calibration error test and linearity check required by appendix B to this part. Whenever the span value is adjusted, use calibration gas concentrations that meet the requirements of section 5.1 of this appendix, based on the adjusted span value. When a span adjustment is significant enough that the calibration gases currently being used for daily calibration error tests and linearity checks are unsuitable for use with the new span value, a diagnostic linearity test using the new calibration gases must be performed and passed. Use the data validation procedures in §75.20(b)(3), beginning with the hour in which the span is changed.

2.1.3 CO_2 and O_2 Monitors

For an O_2 monitor (including O_2 monitors used to measure CO_2 emissions or percentage moisture), select a span value between 15.0 and 25.0 percent O_2. For a CO_2 monitor installed on a boiler, select a span value between 14.0 and 20.0 percent CO_2. For a CO_2 monitor installed on a combustion turbine, an alternative span value between 6.0 and 14.0 percent CO_2 may be used. An alternative CO_2 span value below 6.0 percent may be used if an appropriate technical justification is included in the hardcopy monitoring plan. An alternative O_2 span value below 15.0 percent O_2 may be used if an appropriate technical justification is included in the monitoring plan (e.g., O_2 concentrations above a certain level create an unsafe operating condition). Select the full-scale range of the instrument to be consistent with section 2.1 of this appendix and to be greater than or equal to the span value. Select the calibration gas concentrations for the daily calibration error tests and linearity checks in accordance with section 5.1 of this appendix, as percentages of the span value. For O_2 monitors with span values ≥21.0 percent O_2, purified instrument air containing 20.9 percent O_2 may be used as the high-level calibration material. If a dual-range or autoranging diluent analyzer is installed, the analyzer may be represented in the monitoring plan as a single component, using a special component type code specified by the Administrator to satisfy the requirements of §75.53(e)(1)(iv)(D).

2.1.3.1 Maximum Potential Concentration of CO_2

The MPC and MEC values for diluent monitors are subject to the same periodic review as SO_2 and NO_X monitors (see sections 2.1.1.5 and 2.1.2.5 of this appendix). If an MPC or MEC value is found to be either inappropriately high or low, the MPC shall be adjusted and corresponding span and range adjustments shall be made, if necessary.

For CO_2 pollutant concentration monitors, the maximum potential concentration shall be 14.0 percent CO_2 for boilers and 6.0 percent CO_2 for combustion turbines. Alternatively, the owner or operator may determine the MPC based on a minimum of 720 hours of quality-assured historical CEM data representing the full operating load range of the unit(s). Note that the MPC for CO_2 monitors shall only be used for the purpose of providing substitute data under this part. The CO_2 monitor span and range shall be determined according to section 2.1.3 of this appendix.

2.1.3.2 Minimum Potential Concentration of O_2

The owner or operator of a unit that uses a flow monitor and an O_2 diluent monitor to determine heat input in accordance with Equation F-17 or F-18 in appendix F to this part shall, for the purposes of providing substitute data under §75.36, determine the minimum potential O_2 concentration. The minimum potential O_2 concentration shall be based upon 720 hours or more of quality-assured CEM data, representing the full operating load range of the unit(s). The minimum potential O_2 concentration shall be the lowest quality-assured hourly average O_2 concentration recorded in the 720 (or more) hours of data used for the determination.

2.1.3.3 Adjustment of Span and Range

The MPC and MEC values for diluent monitors are subject to the same periodic review as SO_2 and NO_X monitors (see sections 2.1.1.5 and 2.1.2.5 of this appendix). If an MPC or MEC value is found to be either inappropriately high or low, the MPC shall be adjusted and corresponding span and range adjustments shall be made, if necessary. Adjust the span value and range of a CO_2 or O_2 monitor in accordance with section 2.1.1.5 of this appendix (insofar as those provisions are applicable), with the term “CO_2 or O_2” applying instead of the term “SO_2”. Set the new span and range in accordance with section 2.1.3 of this appendix and report the new span value in the monitoring plan.

2.1.4 Flow Monitors

Select the full-scale range of the flow monitor so that it is consistent with section 2.1 of this appendix and can accurately measure all potential volumetric flow rates at the flow monitor installation site.

2.1.4.1 Maximum Potential Velocity and Flow Rate

For this purpose, determine the span value of the flow monitor using the following procedure. Calculate the maximum potential velocity (MPV) using Equation A-3a or A-3b or determine the MPV (wet basis) from velocity traverse testing using Reference Method 2 (or its allowable alternatives) in appendix A to part 60 of this chapter. If using test values, use the highest average velocity (determined from the Method 2 traverses) measured at or near the maximum unit operating load (or, for units that do not produce electrical or thermal output, at the normal process operating conditions corresponding to the maximum stack gas flow rate). Express the MPV in units of wet standard feet per minute (fpm). For the purpose of providing substitute data during periods of missing flow rate data in accordance with §§75.31 and 75.33 and as required elsewhere in this part, calculate the maximum potential stack gas flow rate (MPF) in units of standard cubic feet per hour (scfh), as the product of the MPV (in units of wet, standard fpm) times 60, times the cross-sectional area of the stack or duct (in ft^2) at the flow monitor location.

$$MPV = \left(\frac{F_d H_f}{A}\right)\left(\frac{20.9}{20.9 - \%O_{2d}}\right)\left(\frac{100}{100 - \%H_2O}\right) \qquad (Eq.\ A\text{-}3a)$$

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or

$$MPV = \left(\frac{F_c H_f}{A}\right)\left(\frac{100}{\%CO_{2d}}\right)\left(\frac{100}{100-\%H_2O}\right) \qquad (Eq.\ A\text{-}3b)$$

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Where:

MPV = maximum potential velocity (fpm, standard wet basis).

F_d = dry-basis F factor (dscf/mmBtu) from Table 1, Appendix F to this part.

F_c = carbon-based F factor (scf CO_2/mmBtu) from Table 1, Appendix F to this part.

Hf = maximum heat input (mmBtu/minute) for all units, combined, exhausting to the stack or duct where the flow monitor is located.

A = inside cross sectional area (ft^2) of the flue at the flow monitor location.

$\%O_{2d}$ = maximum oxygen concentration, percent dry basis, under normal operating conditions.

$\%CO_{2d}$ = minimum carbon dioxide concentration, percent dry basis, under normal operating conditions.

$\%H_2O$ = maximum percent flue gas moisture content under normal operating conditions.

2.1.4.2 Span Values and Range

Determine the span and range of the flow monitor as follows. Convert the MPV, as determined in section 2.1.4.1 of this appendix, to the same measurement units of flow rate that are used for daily calibration error tests (e.g., scfh, kscfh, kacfm, or differential pressure (inches of water)). Next, determine the “calibration span value” by multiplying the MPV (converted to equivalent daily calibration error units) by a factor no less than 1.00 and no greater than 1.25, and rounding up the result to at least two significant figures. For calibration span values in inches of water, retain at least two decimal places. Select appropriate reference signals for the daily calibration error tests as percentages of the calibration span value, as specified in section 2.2.2.1 of this appendix. Finally, calculate the “flow rate span value” (in scfh) as the product of the MPF, as determined in section 2.1.4.1 of this appendix, times the same factor (between 1.00 and 1.25) that was used to calculate the calibration span value. Round off the flow rate span value to the nearest 1000 scfh. Select the full-scale range of the flow monitor so that it is greater than or equal to the span value and is consistent with section 2.1 of this appendix. Include in the monitoring plan for the unit: calculations of the MPV, MPF, calibration span value, flow rate span value, and full-scale range (expressed both in scfh and, if different, in the measurement units of calibration).

2.1.4.3 Adjustment of Span and Range

For each affected unit or common stack, the owner or operator shall make a periodic evaluation of the MPV, MPF, span, and range values for each flow rate monitor (at a minimum, an annual evaluation is required) and shall make any necessary span and range adjustments with corresponding monitoring plan updates, as described in paragraphs (a) through (c) of this section 2.1.4.3. Span and range adjustments may be required, for example, as a result of changes in the fuel supply, changes in the stack or ductwork configuration, changes in the manner of operation of the unit, or installation or removal of emission controls. In implementing the provisions in paragraphs (a) and (b) of this section 2.1.4.3, note that flow rate data recorded during short-term, non-representative operating conditions (e.g., a trial burn of a different type of fuel) shall be excluded from consideration. The owner or operator shall keep the results of the most recent span and range evaluation on-site, in a format suitable for inspection. Make each required span or range adjustment no later than 45 days after the end of the quarter in which the need to adjust the span or range is identified.

(a) If the fuel supply, stack or ductwork configuration, operating parameters, or other conditions change such that the maximum potential flow rate changes significantly, adjust the span and range to assure the continued accuracy of the flow monitor. A “significant” change in the MPV or MPF means that the guidelines of section 2.1 of this appendix can no longer be met, as determined by either a periodic evaluation by the owner or operator or from the results of an audit by the Administrator. The owner or operator should evaluate whether any planned changes in operation of the unit may affect the flow of the unit or stack and should plan any necessary span and range changes needed to account for these changes, so that they are made in as timely a manner as practicable to coordinate with the operational changes. Calculate the adjusted calibration span and flow rate span values using the procedures in section 2.1.4.2 of this appendix.

(b) Whenever the full-scale range is exceeded during a quarter, provided that the exceedance is not caused by a monitor out-of-control period, report 200.0 percent of the current full-scale range as the hourly flow rate for each hour of the full-scale exceedance. If the range is exceeded, make appropriate adjustments to the MPF, flow rate span, and range to prevent future full-scale exceedances. Calculate the new calibration span value by converting the new flow rate span value from units of scfh to units of daily calibration. A calibration error test must be performed and passed to validate data on the new range.

(c) Whenever changes are made to the MPV, MPF, full-scale range, or span value of the flow monitor, as described in paragraphs (a) and (b) of this section, record and report (as applicable) the new full-scale range setting, calculations of the flow rate span value, calibration span value, MPV, and MPF in an updated monitoring plan for the unit. The monitoring plan update shall be made in the quarter in which the changes become effective. Record and report the adjusted calibration span and reference values as parts of the records for the calibration error test required by appendix B to this part. Whenever the calibration span value is adjusted, use reference values for the calibration error test that meet the requirements of section 2.2.2.1 of this appendix, based on the most recent adjusted calibration span value. Perform a calibration error test according to section 2.1.1 of appendix B to this part whenever making a change to the flow monitor span or range, unless the range change also triggers a recertification under §75.20(b).

2.1.5 Minimum Potential Moisture Percentage

Except as provided in section 2.1.6 of this appendix, the owner or operator of a unit that uses a continuous moisture monitoring system to correct emission rates and heat inputs from a dry basis to a wet basis (or vice-versa) shall, for the purpose of providing substitute data under §75.37, use a default value of 3.0 percent H_2O as the minimum potential moisture percentage. Alternatively, the minimum potential moisture percentage may be based upon 720 hours or more of quality-assured CEM data, representing the full operating load range of the unit(s). If this option is chosen, the minimum potential moisture percentage shall be the lowest quality-assured hourly average H_2O concentration recorded in the 720 (or more) hours of data used for the determination.

2.1.6 Maximum Potential Moisture Percentage

When Equation 19-3, 19-4 or 19-8 in Method 19 in appendix A to part 60 of this chapter is used to determine NO_X emission rate, the owner or operator of a unit that uses a continuous moisture monitoring system shall, for the purpose of providing substitute data under §75.37, determine the maximum potential moisture percentage. The maximum potential moisture percentage shall be based upon 720 hours or more of quality-assured CEM data, representing the full operating load range of the unit(s). The maximum potential moisture percentage shall be the highest quality-assured hourly average H_2O concentration recorded in the 720 (or more) hours of data used for the determination. Alternatively, a default maximum potential moisture value of 15.0 percent H_2O may be used.

2.2 Design for Quality Control Testing

2.2.1 Pollutant Concentration and CO_2 or O_2 Monitors

(a) Design and equip each pollutant concentration and CO_2 or O_2 monitor with a calibration gas injection port that allows a check of the entire measurement system when calibration gases are introduced. For extractive and dilution type monitors, all monitoring components exposed to the sample gas, (e.g., sample lines, filters, scrubbers, conditioners, and as much of the probe as practicable) are included in the measurement system. For in situ type monitors, the calibration must check against the injected gas for the performance of all active electronic and optical components (e.g. transmitter, receiver, analyzer).

(b) Design and equip each pollutant concentration or CO_2 or O_2 monitor to allow daily determinations of calibration error (positive or negative) at the zero- and mid-or high-level concentrations specified in section 5.2 of this appendix.

2.2.2 Flow Monitors

Design all flow monitors to meet the applicable performance specifications.

2.2.2.1 Calibration Error Test

Design and equip each flow monitor to allow for a daily calibration error test consisting of at least two reference values: Zero to 20 percent of span or an equivalent reference value (*e.g.,* pressure pulse or electronic signal) and 50 to 70 percent of span. Flow monitor response, both before and after any adjustment, must be capable of being recorded by the data acquisition and handling system. Design each flow monitor to allow a daily calibration error test of the entire flow monitoring system, from and including the probe tip (or equivalent) through and including the data acquisition and handling system, or the flow monitoring system from and including the transducer through and including the data acquisition and handling system.

2.2.2.2 Interference Check

(a) Design and equip each flow monitor with a means to ensure that the moisture expected to occur at the monitoring location does not interfere with the proper functioning of the flow monitoring system. Design and equip each flow monitor with a means to detect, on at least a daily basis, pluggage of each sample line and sensing port, and malfunction of each resistance temperature detector (RTD), transceiver or equivalent.

(b) Design and equip each differential pressure flow monitor to provide an automatic, periodic back purging (simultaneously on both sides of the probe) or equivalent method of sufficient force and frequency to keep the probe and lines sufficiently free of obstructions on at least a daily basis to prevent velocity sensing interference, and a means for detecting leaks in the system on at least a quarterly basis (manual check is acceptable).

(c) Design and equip each thermal flow monitor with a means to ensure on at least a daily basis that the probe remains sufficiently clean to prevent velocity sensing interference.

(d) Design and equip each ultrasonic flow monitor with a means to ensure on at least a daily basis that the transceivers remain sufficiently clean (*e.g.,* backpurging system) to prevent velocity sensing interference.

3. Performance Specifications

3.1 Calibration Error

(a) The calibration error performance specifications in this section apply only to 7-day calibration error tests under sections 6.3.1 and 6.3.2 of this appendix and to the offline calibration demonstration described in section 2.1.1.2 of appendix B to this part. The calibration error limits for daily operation of the continuous monitoring systems required under this part are found in section 2.1.4(a) of appendix B to this part.

(b) The calibration error of SO_2 and NO_X pollutant concentration monitors shall not deviate from the reference value of either the zero or upscale calibration gas by more than 2.5 percent of the span of the instrument, as calculated using Equation A-5 of this appendix. Alternatively, where the span value is less than 200 ppm, calibration error test results are also acceptable if the absolute value of the difference between the monitor response value and the reference value, |R−A| in Equation A-5 of this appendix, is ≤5 ppm. The calibration error of CO_2 or O_2 monitors (including O_2 monitors used to measure CO_2 emissions or percent moisture) shall not deviate from the reference value of the zero or upscale calibration gas by >0.5 percent O_2 or CO_2, as calculated using the term |R−A| in the numerator of Equation A-5 of this appendix. The calibration error of flow monitors shall not exceed 3.0 percent of the calibration span value of the instrument, as calculated using Equation A-6 of this appendix. For differential pressure-type flow monitors, the calibration error test results are also acceptable if |R−A|, the absolute value of the difference between the monitor response and the reference value in Equation A-6, does not exceed 0.01 inches of water.

3.2 Linearity Check

For SO_2 and NO_X pollutant concentration monitors, the error in linearity for each calibration gas concentration (low-, mid-, and high-levels) shall not exceed or deviate from the reference value by more than 5.0 percent (as calculated using equation A-4 of this appendix). Linearity check results are also acceptable if the absolute value of the difference between the average of the monitor response values and the average of the reference values, | R-A | in equation A-4 of this appendix, is less than or equal to 5 ppm. For CO_2 or O_2 monitors (including O_2 monitors used to measure CO_2 emissions or percent moisture):

(1) The error in linearity for each calibration gas concentration (low-, mid-, and high-levels) shall not exceed or deviate from the reference value by more than 5.0 percent as calculated using equation A-4 of this appendix; or

(2) The absolute value of the difference between the average of the monitor response values and the average of the reference values, | R-A| in equation A-4 of this appendix, shall be less than or equal to 0.5 percent CO_2 or O_2, whichever is less restrictive.

3.3 Relative Accuracy

3.3.1 Relative Accuracy for SO_2 Monitors

(a) The relative accuracy for SO_2 pollutant concentration monitors shall not exceed 10.0 percent except as provided in this section.

(b) For affected units where the average of the reference method measurements of SO_2 concentration during the relative accuracy test audit is less than or equal to 250.0 ppm, the difference between the mean value of the monitor measurements and the reference method mean value shall not exceed ±15.0 ppm, wherever the relative accuracy specification of 10.0 percent is not achieved.

3.3.2 Relative Accuracy for NO_X-Diluent Continuous Emission Monitoring Systems

(a) The relative accuracy for NO_X-diluent continuous emission monitoring systems shall not exceed 10.0 percent.

(b) For affected units where the average of the reference method measurements of NO_X emission rate during the relative accuracy test audit is less than or equal to 0.200 lb/mmBtu, the difference between the mean value of the continuous emission monitoring system measurements and the reference method mean value shall not exceed ±0.020 lb/mmBtu, wherever the relative accuracy specification of 10.0 percent is not achieved.

3.3.3 Relative Accuracy for CO_2 and O_2 Monitors

The relative accuracy for CO_2 and O_2 monitors shall not exceed 10.0 percent. The relative accuracy test results are also acceptable if the difference between the mean value of the CO_2 or O_2 monitor measurements and the corresponding reference method measurement mean value, calculated using equation A-7 of this appendix, does not exceed ±1.0 percent CO_2 or O_2.

3.3.4 Relative Accuracy for Flow Monitors

(a) The relative accuracy of flow monitors shall not exceed 10.0 percent at any load (or operating) level at which a RATA is performed (i.e., the low, mid, or high level, as defined in section 6.5.2.1 of this appendix).

(b) For affected units where the average of the flow reference method measurements of gas velocity at a particular load (or operating) level of the relative accuracy test audit is less than or equal to 10.0 fps, the difference between the mean value of the flow monitor velocity measurements and the reference method mean value in fps at that level shall not exceed ±2.0 fps, wherever the 10.0 percent relative accuracy specification is not achieved.

3.3.5 Combined SO_2/Flow Monitoring System [Reserved]

3.3.6 Relative Accuracy for Moisture Monitoring Systems

The relative accuracy of a moisture monitoring system shall not exceed 10.0 percent. The relative accuracy test results are also acceptable if the difference between the mean value of the reference method measurements (in percent H_2O) and the corresponding mean value of the moisture monitoring system measurements (in percent H_2O), calculated using Equation A-7 of this appendix does not exceed ±1.5 percent H_2O.

3.3.7 Relative Accuracy for NO_X Concentration Monitoring Systems

(a) The following requirement applies only to NO_X concentration monitoring systems (i.e., NO_X pollutant concentration monitors) that are used to determine NO_X mass emissions, where the owner or operator elects to monitor and report NO_X mass emissions using a NO_X concentration monitoring system and a flow monitoring system.

(b) The relative accuracy for NO_X concentration monitoring systems shall not exceed 10.0 percent. Alternatively, for affected units where the average of the reference method measurements of NO_X concentration during the relative accuracy test audit is less than or equal to 250.0 ppm, the difference between the mean value of the continuous emission monitoring system measurements and the reference method mean value shall not exceed ±15.0 ppm, wherever the 10.0 percent relative accuracy specification is not achieved.

3.4 Bias

3.4.1 SO_2 Pollutant Concentration Monitors, NO_X Concentration Monitoring Systems and NO_X-Diluent Continuous Emission Monitoring Systems

SO_2 pollutant concentration monitors, NO_X-diluent continuous emission monitoring systems and NO_X concentration monitoring systems used to determine NO_X mass emissions, as defined in §75.71(a)(2), shall not be biased low as determined by the test procedure in section 7.6 of this appendix. The bias specification applies to all SO_2 pollutant concentration monitors and to all NO_X concentration monitoring systems, including those measuring an average SO_2 or NO_X concentration of 250.0 ppm or less, and to all NO_X-diluent continuous emission monitoring systems, including those measuring an average NO_X emission rate of 0.200 lb/mmBtu or less.

3.4.2 Flow Monitors

Flow monitors shall not be biased low as determined by the test procedure in section 7.6 of this appendix. The bias specification applies to all flow monitors including those measuring an average gas velocity of 10.0 fps or less.

3.5 Cycle Time

The cycle time for pollutant concentration monitors, oxygen monitors used to determine percent moisture, and any other monitoring component of a continuous emission monitoring system that is required to perform a cycle time test shall not exceed 15 minutes.

4. Data Acquisition and Handling Systems

(a) Automated data acquisition and handling systems shall read and record the entire range of pollutant concentrations and volumetric flow from zero through full-scale and provide a continuous, permanent record of all measurements and required information in an electronic format. These systems also shall have the capability of interpreting and converting the individual output signals from an SO_2 pollutant concentration monitor, a flow monitor, a CO_2 monitor, an O_2 monitor, a NO_X pollutant concentration monitor, a NO_X-diluent CEMS, and a moisture monitoring system to produce a continuous readout of pollutant emission rates or pollutant mass emissions (as applicable) in the appropriate units (*e.g.,* lb/hr, lb/mmBtu, tons/hr).

(b) Data acquisition and handling systems shall also compute and record: Monitor calibration error; any bias adjustments to SO_2, NO_X, flow rate, or NO_X emission rate data; and all missing data procedure statistics specified in subpart D of this part.

(c) For an excepted monitoring system under appendix D or E of this part, data acquisition and handling systems shall:

(1) Read and record the full range of fuel flowrate through the upper range value;

(2) Calculate and record intermediate values necessary to obtain emissions, such as mass fuel flowrate and heat input rate;

(3) Calculate and record emissions in the appropriate units (e.g., lb/hr of SO_2, lb/mmBtu of NO_X);

(4) Predict and record NO_X emission rate using the heat input rate and the NO_X/heat input correlation developed under appendix E of this part;

(5) Calculate and record all missing data substitution values specified in appendix D or E of this part; and

(6) Provide a continuous, permanent record of all measurements and required information in an electronic format.

5. Calibration Gas

5.1 Reference Gases

For the purposes of part 75, calibration gases include the following:

5.1.1 Standard Reference Materials (SRM)

These calibration gases may be obtained from the National Institute of Standards and Technology (NIST) at the following address: Quince Orchard and Cloppers Road, Gaithersburg, MD 20899-0001.

5.1.2 SRM-Equivalent Compressed Gas Primary Reference Material (PRM)

Contact the Gas Metrology Team, Analytical Chemistry Division, Chemical Science and Technology Laboratory of NIST, at the address in section 5.1.1, for a list of vendors and cylinder gases.

5.1.3 NIST Traceable Reference Materials

Contact the Gas Metrology Team, Analytical Chemistry Division, Chemical Science and Technology Laboratory of NIST, at the address in section 5.1.1, for a list of vendors and cylinder gases that meet the definition for a NIST Traceable Reference Material (NTRM) provided in §72.2.

5.1.4 EPA Protocol Gases

(a) An EPA Protocol gas is a calibration gas mixture prepared and analyzed according to Section 2 of the “EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards,” September 1997, as amended on August 25, 1999, EPA-600/R-97/121 (incorporated by reference, *see* §75.6) or such revised procedure as approved by the Administrator.

(b) EPA Protocol gas concentrations must be certified by an EPA Protocol gas production site to have an analytical uncertainty (95-percent confidence interval) to be not more than plus or minus 2.0 percent (inclusive) of the certified concentration (tag value) of the gas mixture. The uncertainty must be calculated using the statistical procedures (or equivalent statistical techniques) that are listed in Section 2.1.8 of the “EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards,” September 1997, as amended on August 25, 1999, EPA-600/R-97/121 (incorporated by reference, *see* §75.6).

5.1.5 Research Gas Mixtures

Concentrations of research gas mixtures, as defined in §72.2 of this chapter, must be certified by the National Institute of Standards and Technology to have an analytical uncertainty (95-percent confidence interval) calculated using the statistical procedures (or equivalent statistical techniques) that are listed in Section 2.1.8 of the “EPA Traceability Protocol for Assay and

Certification of Gaseous Calibration Standards," September 1997, as amended on August 25, 1999, EPA-600/R-97/121 (incorporated by reference, *see* §75.6) to be not more than plus or minus 2.0 percent (inclusive) of the concentration specified on the cylinder label (*i.e.,* the tag value) in order to be used as calibration gas under this part. Inquiries about the RGM program should be directed to: National Institute of Standards and Technology, Analytical Chemistry Division, Chemical Science and Technology Laboratory, B-324 Chemistry, Gaithersburg, MD 20899.

5.1.6 Zero Air Material

Zero air material is defined in §72.2 of this chapter.

5.1.7 NIST/EPA-Approved Certified Reference Materials

Existing certified reference materials (CRMs) that are still within their certification period may be used as calibration gas.

5.1.8 Gas Manufacturer's Intermediate Standards

Gas manufacturer's intermediate standards is defined in §72.2 of this chapter.

5.2 Concentrations

Four concentration levels are required as follows.

5.2.1 Zero-level Concentration

0.0 to 20.0 percent of span, including span for high-scale or both low- and high-scale for SO_2, NO_X, CO_2, and O_2 monitors, as appropriate.

5.2.2 Low-level Concentration

20.0 to 30.0 percent of span, including span for high-scale or both low- and high-scale for SO_2, NO_X, CO_2, and O_2 monitors, as appropriate.

5.2.3 Mid-level Concentration

50.0 to 60.0 percent of span, including span for high-scale or both low- and high-scale for SO_2, NO_X, CO_2, and O_2 monitors, as appropriate.

5.2.4 High-level Concentration

80.0 to 100.0 percent of span, including span for high-scale or both low-and high-scale for SO_2, NO_X, CO_2, and O_2 monitors, as appropriate.

6. Certification Tests and Procedures

6.1 General Requirements

6.1.1 Pretest Preparation

Install the components of the continuous emission monitoring system (i.e., pollutant concentration monitors, CO_2 or O_2 monitor, and flow monitor) as specified in sections 1, 2, and 3 of this appendix, and prepare each system component and the combined system for operation in accordance with the manufacturer's written instructions. Operate the unit(s) during each period when measurements are made. Units may be tested on non-consecutive days. To the extent practicable, test the DAHS software prior to testing the monitoring hardware.

6.1.2 Requirements for Air Emission Testing

(a) On and after March 27, 2012, all relative accuracy test audits (RATAs) of CEMS under this part, and stack testing under §75.19 and Appendix E to this part shall be conducted by an Air Emission Testing Body (AETB) which has provided to the owner or operator of a unit subject to this part the documentation required in paragraph (b) of this section, demonstrating its conformance to ASTM D7036-04 (incorporated by reference, *see* §75.6).

(b) The owner or operator shall obtain from the AETB a certification that as of the time of testing the AETB is operating in conformance with ASTM D7036-04 (incorporated by reference, *see* §75.6). The AETB's certification may be limited in scope to the tests identified under paragraph (a). The AETB's certification need not extend to other work it may perform. This certification shall be provided in the form of either:

(1) A certificate of accreditation or interim accreditation for the relevant test methods issued by a recognized, national accreditation body; or

(2) A letter of certification for the relevant test methods signed by a member of the senior management staff of the AETB.

(c) The owner or operator shall obtain from the AETB the information required under §§75.59(a)(15), (b)(6), and (d)(4), as applicable.

(d) While under no obligation to request the following information from an AETB, to review the information provided by the AETB in response to such a request, or to take any other action related to the response, the owner or operator may find it useful to request that AETBs complying with paragraph (b)(2) of this section provide a copy of the following:

(1) The AETB's quality manual. For the purpose of application of 40 CFR part 2, subpart B, AETB's concerned about the potential for public access to confidential business information (CBI) may identify any information subject to such a claim in the copy provided;

(2) The results of any internal audits performed by the AETB and any external audits of the AETB during the 12 month period through the previous calendar quarter;

(3) Performance data (as defined in ASTM D7036-04 (incorporated by reference, *see* §75.6)) collected by the AETB, including corrective actions implemented, during the 12 month period through the previous calendar quarter; and

(4) Training records for all on-site technical personnel, including any Qualified Individuals, for the 12 month period through the previous calendar quarter.

(e) All relative accuracy testing performed pursuant to §75.74(c)(2)(ii), section 6.5 of appendix A to this part or section 2.3.1 of appendix B to this part, and stack testing under §75.19 and Appendix E to this part shall be overseen and supervised on site by at least one Qualified Individual, as defined in §72.2 of this chapter with respect to the methods employed in the test project. If the source owner or operator, or a State, local, or EPA observer, discovers while the test team is still on site, that at least one QI did not oversee and supervise the entire test (as qualified by this paragraph (e)), only those portions of the test that were overseen and supervised by at least one QI as described above may be used under this part. However, allowance is made for normal activities of a QI who is overseeing and supervising a test, *e.g.,* bathroom breaks, meal breaks, and emergencies that may arise during a test.

(f) Except as provided in paragraph (e), no RATA performed pursuant to §75.74(c)(2)(ii), section 6.5 of appendix A to this part or section 2.3.1 of appendix B to this part, and no stack test under §75.19 or Appendix E to this part (or portion of such a RATA or stack test) conducted by an AETB (as defined in §72.2) shall be invalidated under this part as a result of the failure of the AETB to conform to ASTM D7036-04 (incorporated by reference, *see* §75.6). Validation of such tests is determined based on the other part 75 testing requirements. EPA recommends that proper observation of tests and review of test results continue, regardless of whether an AETB fully conforms to ASTM D7036-04.

(g) An owner or operator who has requested information from an AETB under paragraph (d) of this part who believes that the information provided by the AETB was either incomplete or inaccurate may request the Administrator's assistance in remedying the alleged deficiencies. Upon such a request, if the Administrator concurs that the information submitted to a source subject to part 75 by an AETB under this section is either incomplete or inaccurate, the Administrator will provide the AETB a description of the deficiencies to be remedied. The Administrator's determination of completeness and accuracy of information will be solely based on the provisions of ASTM D7036-04 (incorporated by reference, *see* §75.6) and this part. The Administrator may post the name of the offending AETB on Agency Web sites (including the CAMD Web site *http://www.epa.gov/airmarkets/emissions/aetb.html*) if within 30 days of the Administrator having provided the AETB a description of the deficiencies to be remedied, the AETB does not satisfactorily respond to the source and notify the Administrator of the response by submitting the notification to *aetb@epa.gov*, unless otherwise provided by the Administrator. The AETB need not submit the information it provides to the owner or operator to the Administrator, unless specifically requested by the Administrator. If after the AETB's name is posted, the Administrator, in consultation with the source, determines that the AETB's response is sufficient, the AETB's name will be removed from the EPA Web sites.

6.2 Linearity Check (General Procedures)

Check the linearity of each SO_2, NO_X, CO_2, and O_2 monitor while the unit, or group of units for a common stack, is combusting fuel at conditions of typical stack temperature and pressure; it is not necessary for the unit to be generating electricity during this test. Notwithstanding these requirements, if the SO_2 or NO_X span value for a particular monitor range is ≤30 ppm, that range is exempted from the linearity check requirements of this part, for initial certification, recertification, and for on-going quality-assurance. For units with two measurement ranges (high and low) for a particular parameter, perform a linearity check on both the low scale (except for SO_2 or NO_X span values ≤30 ppm) and the high scale. Note that for a NO_X-diluent monitoring system with two NO_X measurement ranges, if the low NO_X scale has a span value ≤30 ppm and is exempt from linearity checks, this does not exempt either the diluent monitor or the high NO_X scale (if the span is >30 ppm) from linearity check requirements. For on-going quality assurance of the CEMS, perform linearity checks, using the procedures in this section, on the range(s) and at the frequency specified in section 2.2.1 of appendix B to this part. Challenge each monitor with calibration gas, as defined in section 5.1 of this appendix, at the low-, mid-, and high-range concentrations specified in section 5.2 of this appendix. Introduce the calibration gas at the gas injection port, as specified in section 2.2.1 of this appendix. Operate each monitor at its normal operating temperature and conditions. For extractive and dilution type monitors, pass the calibration gas through all filters, scrubbers, conditioners, and other monitor components used during normal sampling and through as much of the sampling probe as is practical. For in-situ type monitors, perform calibration checking all active electronic and optical components, including the transmitter, receiver, and analyzer. Challenge the monitor three times with each reference gas (see example data sheet in Figure 1). Do not use the same gas twice in succession. To the extent practicable, the duration of each linearity test, from the hour of the first injection to the hour of the last injection, shall not exceed 24 unit operating hours. Record the monitor response from the data acquisition and handling system. For each concentration, use the average of the responses to determine the error in linearity using Equation A-4 in this appendix. Linearity checks are acceptable for monitor or monitoring system certification, recertification, or quality assurance if none of the test results exceed the applicable performance specifications in section 3.2 of this appendix. The status of emission data from a CEMS prior to and during a linearity test period shall be determined as follows:

(a) For the initial certification of a CEMS, data from the monitoring system are considered invalid until all certification tests, including the linearity test, have been successfully completed, unless the conditional data validation procedures in §75.20(b)(3) are used. When the procedures in §75.20(b)(3) are followed, the words “initial certification” apply instead of “recertification,” and complete all of the initial certification tests by the applicable deadline in §75.4, rather than within the time periods specified in §75.20(b)(3)(iv) for the individual tests.

(b) For the routine quality assurance linearity checks required by section 2.2.1 of appendix B to this part, use the data validation procedures in section 2.2.3 of appendix B to this part.

(c) When a linearity test is required as a diagnostic test or for recertification, use the data validation procedures in §75.20(b)(3).

(d) For linearity tests of non-redundant backup monitoring systems, use the data validation procedures in §75.20(d)(2)(iii).

(e) For linearity tests performed during a grace period and after the expiration of a grace period, use the data validation procedures in sections 2.2.3 and 2.2.4, respectively, of appendix B to this part.

(f) For all other linearity checks, use the data validation procedures in section 2.2.3 of appendix B to this part.

6.3 7-Day Calibration Error Test

6.3.1 Gas Monitor 7-Day Calibration Error Test

The following monitors and ranges are exempted from the 7-day calibration error test requirements of this part: the SO_2, NO_X, CO_2 and O_2 monitors installed on peaking units (as defined in §72.2 of this chapter); and any SO_2 or NO_X measurement range with a span value of 50 ppm or less. In all other cases, measure the calibration error of each SO_2 monitor, each NO_X monitor, and each CO_2 or O_2 monitor while the unit is combusting fuel (but not necessarily generating electricity) once each day for 7 consecutive operating days according to the following procedures. (In the event that unit outages occur after the commencement of the test, the 7 consecutive unit operating days need not be 7 consecutive calendar days). Units using dual span monitors must perform the calibration error test on both high- and low-scales of the pollutant concentration monitor. The calibration error test procedures in this section and in section 6.3.2 of this appendix shall also be used to perform the daily assessments and additional calibration error tests required under sections 2.1.1 and 2.1.3 of appendix B to this part. Do not make manual or automatic adjustments to the monitor settings until after taking measurements at both zero and high concentration levels for that day during the 7-day test. If automatic adjustments are made following both injections, conduct the calibration error test such that the magnitude of the adjustments can be determined and recorded. Record and report test results for each day using the unadjusted concentration measured in the calibration error test prior to making any manual or automatic adjustments (*i.e.,* resetting the calibration). The calibration error tests should be approximately 24 hours apart, (unless the 7-day test is performed over nonconsecutive days). Perform calibration error tests at both the zero-level concentration and high-level concentration, as specified in section 5.2 of this appendix. Alternatively, a mid-level concentration gas (50.0 to 60.0 percent of the span value) may be used in lieu of the high-level gas, provided that the mid-level gas is more representative of the actual stack gas concentrations. A calibration gas blend may be used as both a zero-level gas and an upscale (mid- or high-level) gas, where appropriate. In addition, repeat the procedure for SO_2 and NO_X pollutant concentration monitors using the low-scale for units equipped with emission controls or other units with dual span monitors. Use only calibration gas, as specified in section 5.1 of this appendix. Introduce the calibration gas at the gas injection port, as specified in section 2.2.1 of this appendix. Operate each monitor in its normal sampling mode. For extractive and dilution type monitors, pass the calibration gas through all filters, scrubbers, conditioners, and other monitor components used during normal sampling and through as much of the sampling probe as is practical. For in-situ type monitors, perform calibration, checking all active electronic and optical components, including the transmitter, receiver, and analyzer. Challenge the pollutant concentration monitors and CO_2 or O_2 monitors once with each calibration gas. Record the monitor response from the data acquisition and handling system. Using Equation A-5 of this appendix, determine the calibration error at each concentration once each day (at approximately 24-hour intervals) for 7 consecutive days according to the procedures given in this section. The results of a 7-day calibration error test are acceptable for monitor or monitoring system certification, recertification or diagnostic testing if none of these daily calibration error test results exceed the applicable performance specifications in section 3.1 of this appendix. The status of emission data from a gas monitor prior to and during a 7-day calibration error test period shall be determined as follows:

(a) For initial certification, data from the monitor are considered invalid until all certification tests, including the 7-day calibration error test, have been successfully completed, unless the conditional data validation procedures in §75.20(b)(3) are used. When the procedures in §75.20(b)(3) are followed, the words “initial certification” apply instead of “recertification,” and complete all of the initial certification tests by the applicable deadline in §75.4, rather than within the time periods specified in §75.20(b)(3)(iv) for the individual tests.

(b) When a 7-day calibration error test is required as a diagnostic test or for recertification, use the data validation procedures in §75.20(b)(3).

6.3.2 Flow Monitor 7-day Calibration Error Test

Flow monitors installed on peaking units (as defined in §72.2 of this chapter) are exempted from the 7-day calibration error test requirements of this part. In all other cases, perform the 7-day calibration error test of a flow monitor, when required for certification, recertification or diagnostic testing, according to the following procedures. Introduce the reference signal corresponding to the values specified in section 2.2.2.1 of this appendix to the probe tip (or equivalent), or to the transducer. During the 7-day certification test period, conduct the calibration error test while the unit is operating once each unit operating day (as close to 24-hour intervals as practicable). In the event that unit outages occur after the commencement of the test, the 7 consecutive operating days need not be 7 consecutive calendar days. Record the flow monitor responses by means of the data acquisition and handling system. Calculate the calibration error using Equation A-6 of this appendix. Do not perform any corrective maintenance, repair, or replacement upon the flow monitor during the 7-day test period other than that required in the quality assurance/quality control plan required by appendix B to this part. Do not make adjustments between the zero and high reference level measurements on any day during the 7-day test. If the flow monitor operates within the calibration error performance specification (i.e., less than or equal to 3.0 percent error each day and requiring no corrective maintenance, repair, or replacement during the 7-day test period), the flow monitor passes the calibration error test. Record all maintenance activities and the magnitude of any adjustments. Record output readings from the data acquisition and handling system before and after all adjustments. Record and report all calibration error test results using the unadjusted flow rate measured in the calibration error test prior to resetting the calibration. Record all adjustments made during the 7-day period at the time the adjustment is made, and report them in the certification or recertification application. The status of emissions data from a flow monitor prior to and during a 7-day calibration error test period shall be determined as follows:

(a) For initial certification, data from the monitor are considered invalid until all certification tests, including the 7-day calibration error test, have been successfully completed, unless the conditional data validation procedures in §75.20(b)(3) are used. When the procedures in §75.20(b)(3) are followed, the words “initial certification” apply instead of “recertification,” and complete all of the initial certification tests by the applicable deadline in §75.4, rather than within the time periods specified in §75.20(b)(3)(iv) for the individual tests.

(b) When a 7-day calibration error test is required as a diagnostic test or for recertification, use the data validation procedures in §75.20(b)(3).

6.3.3 For gas or flow monitors installed on peaking units, the exemption from performing the 7-day calibration error test applies as long as the unit continues to meet the definition of a peaking unit in §72.2 of this chapter. However, if at the end of a particular calendar year or ozone season, it is determined that peaking unit status has been lost, the owner or operator shall perform a diagnostic 7-day calibration error test of each monitor installed on the unit, by no later than December 31 of the following calendar year.

6.4 Cycle Time Test

Perform cycle time tests for each pollutant concentration monitor and continuous emission monitoring system while the unit is operating, according to the following procedures. Use a zero-level and a high-level calibration gas (as defined in section 5.2 of this appendix) alternately. To determine the downscale cycle time, measure the concentration of the flue gas emissions until the response stabilizes. Record the stable emissions value. Inject a zero-level concentration calibration gas into the probe tip (or injection port leading to the calibration cell, for in situ systems with no probe). Record the time of the zero gas injection, using the data acquisition and handling system (DAHS). Next, allow the monitor to measure the concentration of the zero gas until the response stabilizes. Record the stable ending calibration gas reading. Determine the downscale cycle time as the time it takes for 95.0 percent of the step change to be achieved between the stable stack emissions value and the stable ending zero gas reading. Then repeat the procedure, starting with stable stack emissions and injecting the high-level gas, to determine the upscale cycle time, which is the time it takes for 95.0 percent of the step change to be achieved between the stable stack emissions value and the stable ending high-level gas reading. Use the following criteria to assess when a stable reading of stack emissions or calibration gas concentration has been attained. A stable value is equivalent to a reading with a change of less than 2.0 percent of the span value for 2 minutes, or a reading with a change of less than 6.0 percent from the measured average concentration over 6 minutes. Alternatively, the reading is considered stable if it changes by no more than 0.5 ppm or 0.2% CO_2 or O_2 (as applicable) for two minutes. (Owners or operators of systems which do not record data in 1-minute or 3-minute intervals may petition the Administrator under §75.66 for alternative stabilization criteria). For monitors or monitoring systems that perform a series of operations (such as purge, sample, and analyze), time the injections of the calibration gases so they will produce the longest possible cycle time. Refer to Figures 6a and 6b in this appendix for example calculations of upscale and downscale cycle times. Report the slower of the two cycle times (upscale or downscale) as the cycle time for the analyzer. Prior to January 1, 2009 for the NO_X-diluent continuous emission monitoring system test, either record and report the longer cycle time of the two component analyzers as the system cycle time or record the cycle time for each component analyzer separately (as applicable). On and after January 1, 2009, record the cycle time for each component analyzer separately. For time-shared systems, perform the cycle time tests at each probe locations that will be polled within the same 15-minute period during monitoring system operations. To determine the cycle time for time-shared systems, at each monitoring location, report the sum of the cycle time observed at that monitoring location plus the sum of the time required for all purge cycles (as determined by the continuous emission monitoring system manufacturer) at each of the probe locations of the time-shared systems. For monitors with dual ranges, report the test results for each range separately. Cycle time test results are acceptable for monitor or monitoring system certification, recertification or diagnostic testing if none of the cycle times exceed 15 minutes. The status of emissions data from a monitor prior to and during a cycle time test period shall be determined as follows:

(a) For initial certification, data from the monitor are considered invalid until all certification tests, including the cycle time test, have been successfully completed, unless the conditional data validation procedures in §75.20(b)(3) are used. When the procedures in §75.20(b)(3) are followed, the words “initial certification” apply instead of “recertification,” and complete all of the initial certification tests by the applicable deadline in §75.4, rather than within the time periods specified in §75.20(b)(3)(iv) for the individual tests.

(b) When a cycle time test is required as a diagnostic test or for recertification, use the data validation procedures in §75.20(b)(3).

6.5 Relative Accuracy and Bias Tests (General Procedures)

Perform the required relative accuracy test audits (RATAs) as follows for each CO_2 emissions concentration monitor (including O_2 monitors used to determine CO_2 emissions concentration), each SO_2 pollutant concentration monitor, each NO_X concentration monitoring system used to determine NO_X mass emissions, each flow monitor, each NO_X-diluent CEMS, each O_2 or CO_2 diluent monitor used to calculate heat input, and each moisture monitoring system. For NO_X concentration monitoring systems used to determine NO_X mass emissions, as defined in §75.71(a)(2), use the same general RATA procedures as for SO_2 pollutant concentration monitors; however, use the reference methods for NO_X concentration specified in section 6.5.10 of this appendix:

(a) Except as otherwise provided in this paragraph or in §75.21(a)(5), perform each RATA while the unit (or units, if more than one unit exhausts into the flue) is combusting the fuel that is a normal primary or backup fuel for that unit (for some units, more than one type of fuel may be considered normal, *e.g.*, a unit that combusts gas or oil on a seasonal basis). For units that co-fire fuels as the predominant mode of operation, perform the RATAs while co-firing. For Hg monitoring systems, perform the RATAs while the unit is combusting coal. When relative accuracy test audits are performed on CEMS installed on bypass stacks/ducts, use the fuel normally combusted by the unit (or units, if more than one unit exhausts into the flue) when emissions exhaust through the bypass stack/ducts.

(b) Perform each RATA at the load (or operating) level(s) specified in section 6.5.1 or 6.5.2 of this appendix or in section 2.3.1.3 of appendix B to this part, as applicable.

(c) For monitoring systems with dual ranges, perform the relative accuracy test on the range normally used for measuring emissions. For units with add-on SO_2 or NO_X controls that operate continuously rather than seasonally, or for units that need a dual range to record high concentration “spikes” during startup conditions, the low range is considered normal. However, for some dual span units (*e.g.,* for units that use fuel switching or for which the emission controls are operated seasonally), provided that both monitor ranges are connected to a common probe and sample interface, either of the two measurement ranges may be considered normal; in such cases, perform the RATA on the range that is in use at the time of the scheduled test. If the low and high measurement ranges are connected to separate sample probes and interfaces, RATA testing on both ranges is required.

(d) Record monitor or monitoring system output from the data acquisition and handling system.

(e) Complete each single-load relative accuracy test audit within a period of 168 consecutive unit operating hours, as defined in §72.2 of this chapter (or, for CEMS installed on common stacks or bypass stacks, 168 consecutive stack operating hours, as defined in §72.2 of this chapter). For 2-level and 3-level flow monitor RATAs, complete all of the RATAs at all levels, to the extent practicable, within a period of 168 consecutive unit (or stack) operating hours; however, if this is not possible, up to 720 consecutive unit (or stack) operating hours may be taken to complete a multiple-load flow RATA.

(f) The status of emission data from the CEMS prior to and during the RATA test period shall be determined as follows:

(1) For the initial certification of a CEMS, data from the monitoring system are considered invalid until all certification tests, including the RATA, have been successfully completed, unless the conditional data validation procedures in §75.20(b)(3) are used. When the procedures in §75.20(b)(3) are followed, the words "initial certification" apply instead of "recertification," and complete all of the initial certification tests by the applicable deadline in §75.4, rather than within the time periods specified in §75.20(b)(3)(iv) for the individual tests.

(2) For the routine quality assurance RATAs required by section 2.3.1 of appendix B to this part, use the data validation procedures in section 2.3.2 of appendix B to this part.

(3) For recertification RATAs, use the data validation procedures in §75.20(b)(3).

(4) For quality assurance RATAs of non-redundant backup monitoring systems, use the data validation procedures in §§75.20(d)(2)(v) and (vi).

(5) For RATAs performed during and after the expiration of a grace period, use the data validation procedures in sections 2.3.2 and 2.3.3, respectively, of appendix B to this part.

(6) For all other RATAs, use the data validation procedures in section 2.3.2 of appendix B to this part.

(g) For each SO_2 or CO_2 emissions concentration monitor, each flow monitor, each CO_2 or O_2 diluent monitor used to determine heat input, each NO_X concentration monitoring system used to determine NO_X mass emissions, as defined in §75.71(a)(2), each moisture monitoring system, and each NO_X-diluent CEMS, calculate the relative accuracy, in accordance with section 7.3 or 7.4 of this appendix, as applicable. In addition (except for CO_2, O_2, or moisture monitors), test for bias and determine the appropriate bias adjustment factor, in accordance with sections 7.6.4 and 7.6.5 of this appendix, using the data from the relative accuracy test audits.

6.5.1 Gas Monitoring System RATAs (Special Considerations)

(a) Perform the required relative accuracy test audits for each SO_2 or CO_2 emissions concentration monitor, each CO_2 or O_2 diluent monitor used to determine heat input, each NO_X-diluent CEMS, and each NO_X concentration monitoring system used to determine NO_X mass emissions, as defined in §75.71(a)(2), at the normal load level or normal operating level for the unit (or combined units, if common stack), as defined in section 6.5.2.1 of this appendix. If two load levels or operating levels have been designated as normal, the RATAs may be done at either load (or operating) level.

(b) For the initial certification of a gas monitoring system and for recertifications in which, in addition to a RATA, one or more other tests are required (*i.e.,* a linearity test, cycle time test, or 7-day calibration error test), EPA recommends that the RATA not be commenced until the other required tests of the CEMS have been passed.

6.5.2 Flow Monitor RATAs (Special Considerations)

(a) Except as otherwise provided in paragraph (b) or (e) of this section, perform relative accuracy test audits for the initial certification of each flow monitor at three different exhaust gas velocities (low, mid, and high), corresponding to three different load levels or operating levels within the range of operation, as defined in section 6.5.2.1 of this appendix. For a common stack/duct, the three different exhaust gas velocities may be obtained from frequently used unit/load or operating level combinations for the units exhausting to the common stack. Select the three exhaust gas velocities such that the audit points at adjacent load or operating levels (i.e., low and mid or mid and high), in megawatts (or in thousands of lb/hr of steam production or in ft/sec, as applicable), are separated by no less than 25.0 percent of the range of operation, as defined in section 6.5.2.1 of this appendix.

(b) For flow monitors on bypass stacks/ducts and peaking units, the flow monitor relative accuracy test audits for initial certification and recertification shall be single-load tests, performed at the normal load, as defined in section 6.5.2.1(d) of this appendix.

(c) Flow monitor recertification RATAs shall be done at three load level(s) (or three operating levels), unless otherwise specified in paragraph (b) or (e) of this section or unless otherwise specified or approved by the Administrator.

(d) The semiannual and annual quality assurance flow monitor RATAs required under appendix B to this part shall be done at the load level(s) (or operating levels) specified in section 2.3.1.3 of appendix B to this part.

(e) For flow monitors installed on units that do not produce electrical or thermal output, the flow RATAs for initial certification or recertification may be done at fewer than three operating levels, if:

(1) The owner or operator provides a technical justification in the hardcopy portion of the monitoring plan for the unit required under §75.53(e)(2), demonstrating that the unit operates at only one level or two levels during normal operation (excluding unit startup and shutdown). Appropriate documentation and data must be provided to support the claim of single-level or two-level operation; and

(2) The justification provided in paragraph (e)(1) of this section is deemed to be acceptable by the permitting authority.

6.5.2.1 Range of Operation and Normal Load (or Operating) Level(s)

(a) The owner or operator shall determine the upper and lower boundaries of the "range of operation" as follows for each unit (or combination of units, for common stack configurations):

(1) For affected units that produce electrical output (in megawatts) or thermal output (in klb/hr of steam production or mmBtu/hr), the lower boundary of the range of operation of a unit shall be the minimum safe, stable loads for any of the units discharging through the stack. Alternatively, for a group of frequently-operated units that serve a common stack, the sum of the minimum safe, stable loads for the individual units may be used as the lower boundary of the range of operation. The upper boundary of the range of operation of a unit shall be the maximum sustainable load. The "maximum sustainable load" is the higher of either: the nameplate or rated capacity of the unit, less any physical or regulatory limitations or other deratings; or the highest sustainable load, based on at least four quarters of representative historical operating data. For common stacks, the maximum sustainable load is the sum of all of the maximum sustainable loads of the individual units discharging through the stack, unless this load is unattainable in practice, in which case use the highest sustainable combined load for the units that discharge through the stack. Based on at least four quarters of representative historical operating data. The load values for the unit(s) shall be expressed either in units of megawatts of thousands of lb/hr of steam load or mmBtu/hr of thermal output; or

(2) For affected units that do not produce electrical or thermal output, the lower boundary of the range of operation shall be the minimum expected flue gas velocity (in ft/sec) during normal, stable operation of the unit. The upper boundary of the range of operation shall be the maximum potential flue gas velocity (in ft/sec) as defined in section 2.1.4.1 of this appendix. The minimum expected and maximum potential velocities may be derived from the results of reference method testing or by using Equation A-3a or A-3b (as applicable) in section 2.1.4.1 of this appendix. If Equation A-3a or A-3b is used to determine the minimum expected velocity, replace the word "maximum" with the word "minimum" in the definitions of "MPV," "H_f," "% O_{2d}," and "% H_2O," and replace the word "minimum" with the word "maximum" in the definition of "CO_{2d}." Alternatively, 0.0 ft/sec may be used as the lower boundary of the range of operation.

(b) The operating levels for relative accuracy test audits shall, except for peaking units, be defined as follows: the "low" operating level shall be the first 30.0 percent of the range of operation; the "mid" operating level shall be the middle portion (>30.0 percent, but ≤60.0 percent) of the range of operation; and the "high" operating level shall be the upper end (>60.0 percent) of the range of operation. For example, if the upper and lower boundaries of the range of operation are 100 and 1100 megawatts, respectively, then the low, mid, and high operating levels would be 100 to 400 megawatts, 400 to 700 megawatts, and 700 to 1100 megawatts, respectively.

(c) Units that do not produce electrical or thermal output are exempted from the requirements of this paragraph, (c). The owner or operator shall identify, for each affected unit or common stack (except for peaking units and units using the low mass emissions (LME) excepted methodology under §75.19), the "normal" load level or levels (low, mid or high), based on the operating history of the unit(s). To identify the normal load level(s), the owner or operator shall, at a minimum, determine the relative number of operating hours at each of the three load levels, low, mid and high over the past four representative operating quarters. The owner or operator shall determine, to the nearest 0.1 percent, the percentage of the time that each load level (low, mid, high) has been used during that time period. A summary of the data used for this determination and the calculated results shall be kept on-site in a format suitable for inspection. For new units or newly-affected units, the data analysis in this paragraph may be based on fewer than four quarters of data if fewer than four representative quarters of historical load data are available. Or, if no historical load data are available, the owner or operator may designate the normal load based on the expected or projected manner of operating the unit. However, in either case, once four quarters of representative data become available, the historical load analysis shall be repeated.

(d) Determination of normal load (or operating level)

(1) Based on the analysis of the historical load data described in paragraph (c) of this section, the owner or operator shall, for units that produce electrical or thermal output, designate the most frequently used load level as the normal load level for the unit (or combination of units, for common stacks). The owner or operator may also designate the second most frequently used load level as an additional normal load level for the unit or stack. For peaking units and LME units, normal load designations are unnecessary; the entire operating load range shall be considered normal. If the manner of operation of the unit changes significantly, such that the designated normal load(s) or the two most frequently used load levels change, the owner or operator shall repeat the historical load analysis and shall redesignate the normal load(s) and the two most frequently used load levels, as appropriate. A minimum of two representative quarters of historical load data are required to document that a change in the manner of unit operation has occurred. Update the electronic monitoring plan whenever the normal load level(s) and the two most frequently-used load levels are redesignated.

(2) For units that do not produce electrical or thermal output, the normal operating level(s) shall be determined using sound engineering judgment, based on knowledge of the unit and operating experience with the industrial process.

(e) The owner or operator shall report the upper and lower boundaries of the range of operation for each unit (or combination of units, for common stacks), in units of megawatts or thousands of lb/hr or mmBtu/hr of steam production or ft/sec (as applicable), in the electronic monitoring plan required under §75.53. Except for peaking units and LME units, the owner or operator shall indicate, in the electronic monitoring plan, the load level (or levels) designated as normal under this section and shall also indicate the two most frequently used load levels.

6.5.2.2 Multi-Load (or Multi-Level) Flow RATA Results

For each multi-load (or multi-level) flow RATA, calculate the flow monitor relative accuracy at each operating level. If a flow monitor relative accuracy test is failed or aborted due to a problem with the monitor on any level of a 2-level (or 3-level) relative accuracy test audit, the RATA must be repeated at that load (or operating) level. However, the entire 2-level (or 3-level) relative accuracy test audit does not have to be repeated unless the flow monitor polynomial coefficients or K-factor(s) are changed, in which case a 3-level RATA is required (or, a 2-level RATA, for units demonstrated to operate at only two levels, under section 6.5.2(e) of this appendix).

6.5.3 [Reserved]

6.5.4 Calculations

Using the data from the relative accuracy test audits, calculate relative accuracy and bias in accordance with the procedures and equations specified in section 7 of this appendix.

6.5.5 Reference Method Measurement Location

Select a location for reference method measurements that is (1) accessible; (2) in the same proximity as the monitor or monitoring system location; and (3) meets the requirements of Performance Specification 2 in appendix B of part 60 of this chapter for SO_2 and NO_X continuous emission monitoring systems, Performance Specification 3 in appendix B of part 60 of this chapter for CO_2 or O_2 monitors, or method 1 (or 1A) in appendix A of part 60 of this chapter for volumetric flow, except as otherwise indicated in this section or as approved by the Administrator.

6.5.6 Reference Method Traverse Point Selection

Select traverse points that ensure acquisition of representative samples of pollutant and diluent concentrations, moisture content, temperature, and flue gas flow rate over the flue cross section. To achieve this, the reference method traverse points shall meet the requirements of section 8.1.3 of Performance Specification 2 ("PS No. 2") in appendix B to part 60 of this chapter (for SO_2, NO_X, and moisture monitoring system RATAs), Performance Specification 3 in appendix B to part 60 of this chapter (for O_2 and CO_2 monitor RATAs), Method 1 (or 1A) (for volumetric flow rate monitor RATAs), Method 3 (for molecular weight), and Method 4 (for moisture determination) in appendix A to part 60 of this chapter. The following alternative reference method traverse point locations are permitted for moisture and gas monitor RATAs:

(a) For moisture determinations where the moisture data are used only to determine stack gas molecular weight, a single reference method point, located at least 1.0 meter from the stack wall, may be used. For moisture monitoring system RATAs and for gas monitor RATAs in which moisture data are used to correct pollutant or diluent concentrations from a dry basis to a wet basis (or vice-versa), single-point moisture sampling may only be used if the 12-point stratification test described in section 6.5.6.1 of this appendix is performed prior to the RATA for at least one pollutant or diluent gas, and if the test is passed according to the acceptance criteria in section 6.5.6.3(b) of this appendix.

(b) For gas monitoring system RATAs, the owner or operator may use any of the following options:

(1) At any location (including locations where stratification is expected), use a minimum of six traverse points along a diameter, in the direction of any expected stratification. The points shall be located in accordance with Method 1 in appendix A to part 60 of this chapter.

(2) At locations where section 8.1.3 of PS No. 2 allows the use of a short reference method measurement line (with three points located at 0.4, 1.2, and 2.0 meters from the stack wall), the owner or operator may use an alternative 3-point measurement line, locating the three points at 4.4, 14.6, and 29.6 percent of the way across the stack, in accordance with Method 1 in appendix A to part 60 of this chapter.

(3) At locations where stratification is likely to occur (e.g., following a wet scrubber or when dissimilar gas streams are combined), the short measurement line from section 8.1.3 of PS No. 2 (or the alternative line described in paragraph (b)(2) of this section) may be used in lieu of the prescribed "long" measurement line in section 8.1.3 of PS No. 2, provided that the 12-point stratification test described in section 6.5.6.1 of this appendix is performed and passed one time at the location (according to the acceptance criteria of section 6.5.6.3(a) of this appendix) and provided that either the 12-point stratification test or the alternative (abbreviated) stratification test in section 6.5.6.2 of this appendix is performed and passed prior to each subsequent RATA at the location (according to the acceptance criteria of section 6.5.6.3(a) of this appendix).

(4) A single reference method measurement point, located no less than 1.0 meter from the stack wall and situated along one of the measurement lines used for the stratification test, may be used at any sampling location if the 12-point stratification test described in section 6.5.6.1 of this appendix is performed and passed prior to each RATA at the location (according to the acceptance criteria of section 6.5.6.3(b) of this appendix).

(5) If Method 7E is used as the reference method for the RATA of a NO_X CEMS installed on a combustion turbine, the reference method measurements may be made at the sampling points specified in section 6.1.2 of Method 20 in appendix A to part 60 of this chapter.

6.5.6.1 Stratification Test

(a) With the unit(s) operating under steady-state conditions at the normal load level (or normal operating level), as defined in section 6.5.2.1 of this appendix, use a traversing gas sampling probe to measure the pollutant (SO_2 or NO_X) and diluent (CO_2 or O_2) concentrations at a minimum of twelve (12) points, located according to Method 1 in appendix A to part 60 of this chapter.

(b) Use Methods 6C, 7E, and 3A in appendix A to part 60 of this chapter to make the measurements. Data from the reference method analyzers must be quality-assured by performing analyzer calibration error and system bias checks before the series of measurements and by conducting system bias and calibration drift checks after the measurements, in accordance with the procedures of Methods 6C, 7E, and 3A.

(c) Measure for a minimum of 2 minutes at each traverse point. To the extent practicable, complete the traverse within a 2-hour period.

(d) If the load has remained constant (±3.0 percent) during the traverse and if the reference method analyzers have passed all of the required quality assurance checks, proceed with the data analysis.

(e) Calculate the average NO_X, SO_2, and CO_2 (or O_2) concentrations at each of the individual traverse points. Then, calculate the arithmetic average NO_X, SO_2, and CO_2 (or O_2) concentrations for all traverse points.

6.5.6.2 Alternative (Abbreviated) Stratification Test

(a) With the unit(s) operating under steady-state conditions at normal load level (or normal operating level), as defined in section 6.5.2.1 of this appendix, use a traversing gas sampling probe to measure the pollutant (SO_2 or NO_X) and diluent (CO_2 or O_2) concentrations at three points. The points shall be located according to the specifications for the long measurement line in section 8.1.3 of PS No. 2 (i.e., locate the points 16.7 percent, 50.0 percent, and 83.3 percent of the way across the stack). Alternatively, the concentration measurements may be made at six traverse points along a diameter. The six points shall be located in accordance with Method 1 in appendix A to part 60 of this chapter.

(b) Use Methods 6C, 7E, and 3A in appendix A to part 60 of this chapter to make the measurements. Data from the reference method analyzers must be quality-assured by performing analyzer calibration error and system bias checks before the series of measurements and by conducting system bias and calibration drift checks after the measurements, in accordance with the procedures of Methods 6C, 7E, and 3A.

(c) Measure for a minimum of 2 minutes at each traverse point. To the extent practicable, complete the traverse within a 1-hour period.

(d) If the load has remained constant (±3.0 percent) during the traverse and if the reference method analyzers have passed all of the required quality assurance checks, proceed with the data analysis.

(e) Calculate the average NO_X, SO_2, and CO_2 (or O_2) concentrations at each of the individual traverse points. Then, calculate the arithmetic average NO_X, SO_2, and CO_2 (or O_2) concentrations for all traverse points.

6.5.6.3 Stratification Test Results and Acceptance Criteria

(a) For each pollutant or diluent gas, the short reference method measurement line described in section 8.1.3 of PS No. 2 may be used in lieu of the long measurement line prescribed in section 8.1.3 of PS No. 2 if the results of a stratification test, conducted in accordance with section 6.5.6.1 or 6.5.6.2 of this appendix (as appropriate; see section 6.5.6(b)(3) of this appendix), show that the concentration at each individual traverse point differs by no more than ±10.0 percent from the arithmetic average concentration for all traverse points. The results are also acceptable if the concentration at each individual traverse point differs by no more than ±5ppm or ±0.5 percent CO_2 (or O_2) from the arithmetic average concentration for all traverse points.

(b) For each pollutant or diluent gas, a single reference method measurement point, located at least 1.0 meter from the stack wall and situated along one of the measurement lines used for the stratification test, may be used for that pollutant or diluent gas if the results of a stratification test, conducted in accordance with section 6.5.6.1 of this appendix, show that the concentration at each individual traverse point differs by no more than ±5.0 percent from the arithmetic average concentration for all traverse points. The results are also acceptable if the concentration at each individual traverse point differs by no more than ±3 ppm or ±0.3 percent CO_2 (or O_2) from the arithmetic average concentration for all traverse points.

(c) The owner or operator shall keep the results of all stratification tests on-site, in a format suitable for inspection, as part of the supplementary RATA records required under §75.59(a)(7).

6.5.7 Sampling Strategy

(a) Conduct the reference method tests allowed in section 6.5.10 of this appendix so they will yield results representative of the pollutant concentration, emission rate, moisture, temperature, and flue gas flow rate from the unit and can be correlated with the pollutant concentration monitor, CO_2 or O_2 monitor, flow monitor, and SO_2 or NO_X CEMS measurements. The minimum acceptable time for a gas monitoring system RATA run or for a moisture monitoring system RATA run is 21 minutes. For each run of a gas monitoring system RATA, all necessary pollutant concentration measurements, diluent concentration measurements, and moisture measurements (if applicable) must, to the extent practicable, be made within a 60-minute period. For NO_X-diluent monitoring system RATAs, the pollutant and diluent concentration measurements must be made simultaneously. For flow monitor RATAs, the minimum time per run shall be 5 minutes. Flow rate reference method measurements allowed in section 6.5.10 of this appendix may be made either sequentially from port-to-port or simultaneously at two or more sample ports. The velocity measurement probe may be moved from traverse point to traverse point either manually or automatically. If, during a flow RATA, significant pulsations in the reference method readings are observed, be sure to allow enough measurement time at each traverse point to obtain an accurate average reading when a manual readout method is used (*e.g.,* a "sight-weighted" average from a manometer). Also, allow sufficient measurement time to ensure that stable temperature readings are obtained at each traverse point, particularly at the first measurement point at each sample port, when a probe is moved sequentially from port-to-port. A minimum of one set of auxiliary measurements for stack gas molecular weight determination (*i.e.,* diluent gas data and moisture data) is required for every clock hour of a flow RATA or for every three test runs (whichever is less restrictive). Alternatively, moisture measurements for molecular weight determination may be performed before and after a series of flow RATA runs at a particular load level (low, mid, or high), provided that the time interval between the two moisture measurements does not exceed three hours. If this option is selected, the results of the two moisture determinations shall be averaged arithmetically and applied to all RATA runs in the series. Successive flow RATA runs may be performed without waiting in between runs. If an O_2 diluent monitor is used as a CO_2 continuous emission monitoring system, perform a CO_2 system RATA (*i.e.,* measure CO_2, rather than O_2, with the applicable reference method allowed in section 6.5.10 of this appendix). For moisture monitoring systems, an appropriate coefficient, "K" factor or other suitable mathematical algorithm may be developed prior to the RATA, to adjust the monitoring system readings with respect to the applicable reference method allowed in section 6.5.10 of this appendix. If such a coefficient, K-factor or algorithm is developed, it shall be applied to the CEMS readings during the RATA and (if the RATA is passed), to the subsequent CEMS data, by means of the automated data acquisition and handling system. The owner or operator shall keep records of the current coefficient, K factor or algorithm, as specified in §75.59(a)(5)(vii). Whenever the coefficient, K factor or algorithm is changed, a RATA of the moisture monitoring system is required.

(b) To properly correlate individual SO_2 or NO_X CEMS data (in lb/mmBtu) and volumetric flow rate data with the applicable reference method data, annotate the beginning and end of each reference method test run (including the exact time of day) on the individual chart recorder(s) or other permanent recording device(s).

6.5.8 Correlation of Reference Method and Continuous Emission Monitoring System

Confirm that the monitor or monitoring system and reference method test results are on consistent moisture, pressure, temperature, and diluent concentration basis (e.g., since the flow monitor measures flow rate on a wet basis, method 2 test results must also be on a wet basis). Compare flow-monitor and reference method results on a scfh basis. Also, consider the response times of the pollutant concentration monitor, the continuous emission monitoring system, and the flow monitoring system to ensure comparison of simultaneous measurements.

For each relative accuracy test audit run, compare the measurements obtained from the monitor or continuous emission monitoring system (in ppm, percent CO_2, lb/mmBtu, or other units) against the corresponding reference method values. Tabulate the paired data in a table such as the one shown in Figure 2.

6.5.9 Number of Reference Method Tests

Perform a minimum of nine sets of paired monitor (or monitoring system) and reference method test data for every required (i.e., certification, recertification, diagnostic, semiannual, or annual) relative accuracy test audit. For 2-level and 3-level relative accuracy test audits of flow monitors, perform a minimum of nine sets at each of the operating levels.

NOTE: The tester may choose to perform more than nine sets of reference method tests. If this option is chosen, the tester may reject a maximum of three sets of the test results, as long as the total number of test results used to determine the relative accuracy or bias is greater than or equal to nine. Report all data, including the rejected CEMS data and corresponding reference method test results.

6.5.10 Reference Methods

The following methods are from appendix A to part 60 of this chapter, and are the reference methods for performing relative accuracy test audits under this part: Method 1 or 1A in appendix A-1 to part 60 of this chapter for siting; Method 2 in appendix A-1 to part 60 of this chapter or its allowable alternatives in appendices A-1 and A-2 to part 60 of this chapter (except for Methods 2B and 2E in appendix A-1 to part 60 of this chapter) for stack gas velocity and volumetric flow rate; Methods 3, 3A or 3B in appendix A-2 to part 60 of this chapter for O_2 and CO_2; Method 4 in appendix A-3 to part 60 of this chapter for moisture; Methods 6, 6A or 6C in appendix A-4 to part 60 of this chapter for SO_2; and Methods 7, 7A, 7C, 7D or 7E in appendix A-4 to part 60 of this chapter for NO_X, excluding the exceptions to Method 7E identified in §75.22(a)(5). When using Method 7E for measuring NO_X concentration, total NO_X, including both NO and NO_2, must be measured. When using EPA Protocol gas with Methods 3A, 6C, and 7E, the gas must be from an EPA Protocol gas production site that is participating in the EPA Protocol Gas Verification Program, pursuant to §75.21(g)(6). An EPA Protocol gas cylinder certified by or ordered from a non-participating production site no later than May 27, 2011 may be used for the purposes of this part until the earlier of the cylinder's expiration date or the date on which the cylinder gas pressure reaches 150 psig; however, in no case shall the cylinder be recertified by a non-participating EPA Protocol gas production site to extend its useful life and be used by a source subject to this part. In the event that an EPA Protocol gas production site is removed from the list of PGVP participants on the same date as or after the date on which a particular cylinder is certified or ordered, that gas cylinder may continue to be used for the purposes of this part until the earlier of the cylinder's expiration date or the date on which the cylinder gas pressure reaches 150 psig; however, in no case shall the cylinder be recertified by a non-participating EPA Protocol gas production site to extend its useful life and be used by a source subject to this part.

7. CALCULATIONS

7.1 Linearity Check

Analyze the linearity data for pollutant concentration and CO_2 or O_2 monitors as follows. Calculate the percentage error in linearity based upon the reference value at the low-level, mid-level, and high-level concentrations specified in section 6.2 of this appendix. Perform this calculation once during the certification test. Use the following equation to calculate the error in linearity for each reference value.

$$LE = \frac{|R-A|}{R} \times 100$$

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(Eq. A-4)

where,

LE = Percentage Linearity error, based upon the reference value.

R = Reference value of Low-, mid-, or high-level calibration gas introduced into the monitoring system.

A = Average of the monitoring system responses.

7.2 Calibration Error

7.2.1 Pollutant Concentration and Diluent Monitors

For each reference value, calculate the percentage calibration error based upon instrument span for daily calibration error tests using the following equation:

$$CE = \frac{|R-A|}{S} \times 100$$

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(Eq. A-5)

where,

CE = Calibration error as a percentage of the span of the instrument.

R = Reference value of zero or upscale (high-level or mid-level, as applicable) calibration gas introduced into the monitoring system.

A = Actual monitoring system response to the calibration gas.

S = Span of the instrument, as specified in section 2 of this appendix.

7.2.2 Flow Monitor Calibration Error

For each reference value, calculate the percentage calibration error based upon span using the following equation:

$$CE = \frac{|R-A|}{S} \times 100 \qquad (Eq.\ A\text{-}6)$$

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where:

CE = Calibration error as a percentage of span.

R = Low or high level reference value specified in section 2.2.2.1 of this appendix.

A = Actual flow monitor response to the reference value.

S = Flow monitor calibration span value as determined under section 2.1.4.2 of this appendix.

7.3 Relative Accuracy for SO_2 and CO_2 Emissions Concentration Monitors, O_2 Monitors, NO_X Concentration Monitoring Systems, and Flow Monitors

Analyze the relative accuracy test audit data from the reference method tests for SO_2 and CO_2 emissions concentration monitors, CO_2 or O_2 monitors used for heat input rate determination, NO_X concentration monitoring systems used to determine NO_X mass emissions under subpart H of this part, and flow monitors using the following procedures. Summarize the results on a data sheet. An example is shown in Figure 2. Calculate the mean of the monitor or monitoring system measurement values. Calculate the mean of the reference method values. Using data from the automated data acquisition and handling system, calculate the arithmetic differences between the reference method and monitor measurement data sets. Then calculate the arithmetic mean of the difference, the standard deviation, the confidence coefficient, and the monitor or monitoring system relative accuracy using the following procedures and equations.

7.3.1 Arithmetic Mean

Calculate the arithmetic mean of the differences of a data set as follows:

$$\bar{d} = \frac{1}{n}\sum_{i=1}^{n} d_i \qquad \text{(Eq. A-7)}$$

Where:

$\bar{d}$ = Arithmetic mean of the differences

n = Number of data points (test runs)

$\sum_{i=1}^{n} d_i$ = Algebraic sum of the individual differences d_i

d_i = The difference between a reference method value and the corresponding continuous emission monitoring system value ($RM_i - CEM_i$), for a given data point

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7.3.2 Standard Deviation

Calculate the standard deviation, S_d, of a data set as follows:

$$S_d = \sqrt{\frac{\sum_{i=1}^{n} d_i^2 - \left[\frac{\left(\sum_{i=1}^{n} d_i\right)^2}{n}\right]}{n-1}}$$

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(Eq. A-8)

7.3.3 Confidence Coefficient

Calculate the confidence coefficient (one-tailed), cc, of a data set as follows.

$$cc = t_{0.025}\,\frac{S_d}{\sqrt{n}}$$

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(eq. A-9)

where,

$t_{0.025}$ = t value (see table 7-1).

Table 7-1—t-Values

n-1	$t_{0.025}$	n-1	$t_{0.025}$	n-1	$t_{0.025}$
1	12.706	12	2.179	23	2.069
2	4.303	13	2.160	24	2.064
3	3.182	14	2.145	25	2.060
4	2.776	15	2.131	26	2.056
5	2.571	16	2.120	27	2.052
6	2.447	17	2.110	28	2.048
7	2.365	18	2.101	29	2.045
8	2.306	19	2.093	30	2.042
9	2.262	20	2.086	40	2.021
10	2.228	21	2.080	60	2.000
11	2.201	22	2.074	>60	1.960

7.3.4 Relative Accuracy

Calculate the relative accuracy of a data set using the following equation.

$$RA = \frac{|\bar{d}| + |cc|}{RM} \times 100$$

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(Eq. A-10)

where,

RM = Arithmetic mean of the reference method values.

$|\bar{d}|$ = The absolute value of the mean difference between the reference method values and the corresponding continuous emission monitoring system values.

|cc| = The absolute value of the confidence coefficient.

7.4 Relative Accuracy for NO_X-diluent Continuous Emission Monitoring Systems

Analyze the relative accuracy test audit data from the reference method tests for NO_X-diluent continuous emissions monitoring system as follows.

7.4.1 Data Preparation

If C_{NOx}, the NO_X concentration, is in ppm, multiply it by 1.194×10^{-7} (lb/dscf)/ppm to convert it to units of lb/dscf. If C_{NOx} is in mg/dscm, multiply it by 6.24×10^{-8} (lb/dscf)/(mg/dscm) to convert it to lb/dscf. Then, use the diluent (O_2 or CO_2) reference method results for the run and the appropriate F or F_c factor from table 1 in appendix F of this part to convert C_{NOx} from lb/dscf to lb/mmBtu units. Use the equations and procedure in section 3 of appendix F to this part, as appropriate.

7.4.2 NO_X Emission Rate

For each test run in a data set, calculate the average NO_X emission rate (in lb/mmBtu), by means of the data acquisition and handling system, during the time period of the test run. Tabulate the results as shown in example Figure 4.

7.4.3 Relative Accuracy

Use the equations and procedures in section 7.3 above to calculate the relative accuracy for the NO_X continuous emission monitoring system. In using equation A-7, "d" is, for each run, the difference between the NO_X emission rate values (in lb/mmBtu) obtained from the reference method data and the NO_X continuous emission monitoring system.

7.5 Relative Accuracy for Combined SO_2/Flow [Reserved]

7.6 Bias Test and Adjustment Factor

Test the following relative accuracy test audit data sets for bias: SO_2 pollutant concentration monitors; flow monitors; NO_X concentration monitoring systems used to determine NO_X mass emissions, as defined in 75.71(a)(2); and NO_X-diluent CEMS using the procedures outlined in sections 7.6.1 through 7.6.5 of this appendix. For multiple-load flow RATAs, perform a bias test at each load level designated as normal under section 6.5.2.1 of this appendix.

7.6.1 Arithmetic Mean

Calculate the arithmetic mean of the differences of the data set using Equation A-7 of this appendix. To calculate bias for an SO_2 or NO_X pollutant concentration monitor, "d_i" is, for each paired data point, the difference between the SO_2 or NO_X concentration value (in ppm) obtained from the reference method and the monitor. To calculate bias for a flow monitor, "d_i" is, for each paired data point, the difference between the flow rate values (in scfh) obtained from the reference method and the monitor. To calculate bias for a NO_X-diluent continuous emission monitoring system, "d_i" is, for each paired data point, the difference between the NO_X emission rate values (in lb/mmBtu) obtained from the reference method and the monitoring system.

7.6.2 Standard Deviation

Calculate the standard deviation, S_d, of the data set using equation A-8.

7.6.3 Confidence Coefficient

Calculate the confidence coefficient, cc, of the data set using equation A-9.

7.6.4 Bias Test

If, for the relative accuracy test audit data set being tested, the mean difference, $\bar{d}$, is less than or equal to the absolute value of the confidence coefficient, | cc |, the monitor or monitoring system has passed the bias test. If the mean difference, $\bar{d}$, is greater than the absolute value of the confidence coefficient, √ cc √, the monitor or monitoring system has failed to meet the bias test requirement.

7.6.5 Bias Adjustment

(a) If the monitor or monitoring system fails to meet the bias test requirement, adjust the value obtained from the monitor using the following equation:

$$CEM_i^{Adjusted} = CEM_i^{Monitor} \times BAF \qquad (Eq.\ A\text{-}11)$$

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Where:

$CEM_i^{Monitor}$ = Data (measurement) provided by the monitor at time i.

$CEM_i^{Adjusted}$ = Data value, adjusted for bias, at time i.

BAF = Bias adjustment factor, defined by:

$$BAF = 1 + \frac{|\bar{d}|}{CEM_{avg}} \qquad (Eq.\ A\text{-}12)$$

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Where:

BAF = Bias adjustment factor, calculated to the nearest thousandth.

$\bar{d}$= Arithmetic mean of the difference obtained during the failed bias test using Equation A-7.

CEM_{avg} = Mean of the data values provided by the monitor during the failed bias test.

(b) For single-load RATAs of SO_2 pollutant concentration monitors, NO_X concentration monitoring systems, and NO_X-diluent monitoring systems, and for the single-load flow RATAs required or allowed under section 6.5.2 of this appendix and sections 2.3.1.3(b) and 2.3.1.3(c) of appendix B to this part, the appropriate BAF is determined directly from the RATA results at normal load, using Equation A-12. Notwithstanding, when a NO_X concentration CEMS or an SO_2 CEMS or a NO_X-diluent CEMS installed on a low-emitting affected unit (*i.e.,* average SO_2 or NO_X concentration during the RATA ≤250 ppm or average NO_X emission rate ≤0.200 lb/mmBtu) meets the normal 10.0 percent relative accuracy specification (as calculated using Equation A-10) or the alternate relative accuracy specification in section 3.3 of this appendix for low-emitters, but fails the bias test, the BAF may either be determined using Equation A-12, or a default BAF of 1.111 may be used.

(c) For 2-load or 3-load flow RATAs, when only one load level (low, mid or high) has been designated as normal under section 6.5.2.1 of this appendix and the bias test is passed at the normal load level, apply a BAF of 1.000 to the subsequent flow rate data. If the bias test is failed at the normal load level, use Equation A-12 to calculate the normal load BAF and then perform an additional bias test at the second most frequently-used load level, as determined under section 6.5.2.1 of this appendix. If the bias test is passed at this second load level, apply the normal load BAF to the subsequent flow rate data. If the bias test is failed at this second load level, use Equation A-12 to calculate the BAF at the second load level and apply the higher of the two BAFs (either from the normal load level or from the second load level) to the subsequent flow rate data.

(d) For 2-load or 3-load flow RATAs, when two load levels have been designated as normal under section 6.5.2.1 of this appendix and the bias test is passed at both normal load levels, apply a BAF of 1.000 to the subsequent flow rate data. If the bias test is failed at one of the normal load levels but not at the other, use Equation A-12 to calculate the BAF for the normal load level at which the bias test was failed and apply that BAF to the subsequent flow rate data. If the bias test is failed at both designated normal load levels, use Equation A-12 to calculate the BAF at each normal load level and apply the higher of the two BAFs to the subsequent flow rate data.

(e) Each time a RATA is passed and the appropriate bias adjustment factor has been determined, apply the BAF prospectively to all monitoring system data, beginning with the first clock hour following the hour in which the RATA was completed. For a 2-load flow RATA, the “hour in which the RATA was completed” refers to the hour in which the testing at both loads was completed; for a 3-load RATA, it refers to the hour in which the testing at all three loads was completed.

(f) Use the bias-adjusted values in computing substitution values in the missing data procedure, as specified in subpart D of this part, and in reporting the concentration of SO_2, the flow rate, the average NO_X emission rate, the unit heat input, and the calculated mass emissions of SO_2 and CO_2 during the quarter and calendar year, as specified in subpart G of this part. In addition, when using a NO_X concentration monitoring system and a flow monitor to calculate NO_X mass emissions under subpart H of this part, use bias-adjusted values for NO_X concentration and flow rate in the mass emission calculations and use bias-adjusted NO_X concentrations to compute the appropriate substitution values for NO_X concentration in the missing data routines under subpart D of this part.

(g) For units that do not produce electrical or thermal output, the provisions of paragraphs (a) through (f) of this section apply, except that the terms, “single-load”, “2-load”, “3-load”, and “load level” shall be replaced, respectively, with the terms, “single-level”, “2-level”, “3-level”, and “operating level”.

7.7 Reference Flow-to-Load Ratio or Gross Heat Rate

(a) Except as provided in section 7.8 of this appendix, the owner or operator shall determine R_{ref}, the reference value of the ratio of flow rate to unit load, each time that a passing flow RATA is performed at a load level designated as normal in section 6.5.2.1 of this appendix. The owner or operator shall report the current value of R_{ref} in the electronic quarterly report required under §75.64 and shall also report the completion date of the associated RATA. If two load levels have been designated as normal under section 6.5.2.1 of this appendix, the owner or operator shall determine a separate R_{ref} value for each of the normal load levels. The reference flow-to-load ratio shall be calculated as follows:

$$R_{ref} = \frac{Q_{ref}}{L_{avg}} \times 10^{-5} \qquad (Eq.\ A\text{-}13)$$

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Where:

R_{ref} = Reference value of the flow-to-load ratio, from the most recent normal-load flow RATA, scfh/megawatts, scfh/1000 lb/hr of steam, or scfh/(mmBtu/hr of steam output).

Q_{ref} = Average stack gas volumetric flow rate measured by the reference method during the normal-load RATA, scfh.

L_{avg} = Average unit load during the normal-load flow RATA, megawatts, 1000 lb/hr of steam, or mmBtu/hr of thermal output.

(b) In Equation A-13, for a common stack, determine L_{avg} by summing, for each RATA run, the operating loads of all units discharging through the common stack, and then taking the arithmetic average of the summed loads. For a unit that discharges its emissions through multiple stacks, either determine a single value of Q_{ref} for the unit or a separate value of Q_{ref} for each stack. In the former case, calculate Q_{ref} by summing, for each RATA run, the volumetric flow rates through the individual stacks and then taking the arithmetic average of the summed RATA run flow rates. In the latter case, calculate the value of Q_{ref} for each stack by taking the arithmetic average, for all RATA runs, of the flow rates through the stack. For a unit with a multiple stack discharge configuration consisting of a main stack and a bypass stack (e.g., a unit with a wet SO_2 scrubber), determine Q_{ref} separately for each stack at the time of the normal load flow RATA. Round off the value of R_{ref} to two decimal places.

(c) In addition to determining R_{ref} or as an alternative to determining R_{ref}, a reference value of the gross heat rate (GHR) may be determined. In order to use this option, quality-assured diluent gas (CO_2 or O_2) must be available for each hour of the most recent normal-load flow RATA. The reference value of the GHR shall be determined as follows:

$$(GHR)_{ref} = \frac{(Heat\ Input)_{avg}}{L_{avg}} \times 1000 \qquad (Eq.\ A\text{-}13a)$$

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Where:

$(GHR)_{ref}$ = Reference value of the gross heat rate at the time of the most recent normal-load flow RATA, Btu/kwh, Btu/lb steam load, or Btu heat input/mmBtu steam output.

$(Heat\ Input)_{avg}$ = Average hourly heat input during the normal-load flow RATA, as determined using the applicable equation in appendix F to this part, mmBtu/hr. For multiple stack configurations, if the reference GHR value is determined separately for each stack, use the hourly heat input measured at each stack. If the reference GHR is determined at the unit level, sum the hourly heat inputs measured at the individual stacks.

L_{avg} = Average unit load during the normal-load flow RATA, megawatts, 1000 lb/hr of steam, or mmBtu/hr thermal output.

(d) In the calculation of $(Heat\ Input)_{avg}$, use Q_{ref}, the average volumetric flow rate measured by the reference method during the RATA, and use the average diluent gas concentration measured during the flow RATA (i.e., the arithmetic average of the diluent gas concentrations for all clock hours in which a RATA run was performed).

7.8 Flow-to-Load Test Exemptions

(a) For complex stack configuations (e.g., when the effluent from a unit is divided and discharges through multiple stacks in such a manner that the flow rate in the individual stacks cannot be correlated with unit load), the owner or operator may petition the Administrator under §75.66 for an exemption from the requirements of section 7.7 of this appendix and section 2.2.5 fo appendix B to this part. The petition must include sufficient information and data to demonstrate that a flow-to-load or gross heat rate evaluation is infeasible for the complex stack configuration.

(b) Units that do not produce electrical output (in megawatts) or thermal output (in klb of steam per hour) are exempted from the flow-to-load ratio test requirements of section 7.7 of this appendix and section 2.2.5 of appendix B to this part.

Figure 1 to Appendix A—Linearity Error Determination

Day	Date and time	Reference value	Monitor value	Difference	Percent of reference value
Low-level:					
Mid-level:					
High-level:					

Figure 2 to Appendix A—Relative Accuracy Determination (Pollutant Concentration Monitors)

Run No.	Date and time	SO_2 (ppm[c])			Date and time	CO_2 (Pollutant) (ppm[c])		
		RM[a]	M[b]	Diff		RM[a]	M[b]	Diff
1								
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
Arithmetic Mean Difference (Eq. A-7). Confidence Coefficient (Eq. A-9). Relative Accuracy (Eq. A-10).								

[a]RM means "reference method data."

[b]M means "monitor data."

[c]Make sure the RM and M data are on a consistent basis, either wet or dry.

Figure 3 to Appendix A—Relative Accuracy Determination (Flow Monitors)

Run No.	Date and time	Flow rate (Low) (scf/hr)*			Date and time	Flow rate (Normal) (scf/hr)*			Date and time	Flow rate (High) (scf/hr)*		
		RM	M	Diff		RM	M	Diff		RM	M	Diff
1												
2												

3												
4												
5												
6												
7												
8												
9												
10												
11												
12												
Arithmetic Mean Difference (Eq. A-7). Confidence Coefficient (Eq. A-9). Relative Accuracy (Eq. A-10).												

*Make sure the RM and M data are on a consistent basis, either wet or dry.

Figure 4 to Appendix A—Relative Accuracy Determination (NO_X/Diluent Combined System)

Run No.	Date and time	Reference method data		NO_X system (lb/mmBtu)		
		NO_X( )[a]	O_2/CO_2%	RM	M	Difference
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
Arithmetic Mean Difference (Eq. A-7). Confidence Coefficient (Eq. A-9). Relative Accuracy (Eq. A-10).						

[a]Specify units: ppm, lb/dscf, mg/dscm.

Figure 5—Cycle Time

Date of test____________________

Component/system ID#:____________________

Analyzer type____________________

Serial Number____________________

High level gas concentration: ___ ppm/% (circle one)

Zero level gas concentration: ___ ppm/% (circle one)

Analyzer span setting: ___ ppm/% (circle one)

Upscale:

Stable starting monitor value: ___ ppm/% (circle one)

Stable ending monitor reading: ___ ppm/% (circle one)

Elapsed time: ___ seconds

Downscale:

Stable starting monitor value: ___ ppm/% (circle one)

Stable ending monitor value: ___ ppm/% (circle one)

Elapsed time: ___ seconds

Component cycle time= ___ seconds

System cycle time= ___ seconds

Figure 6a. Upscale Cycle Time Test

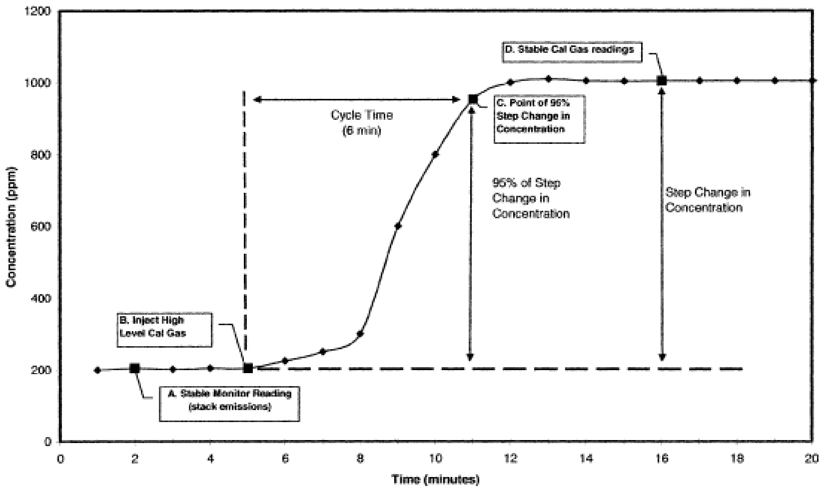

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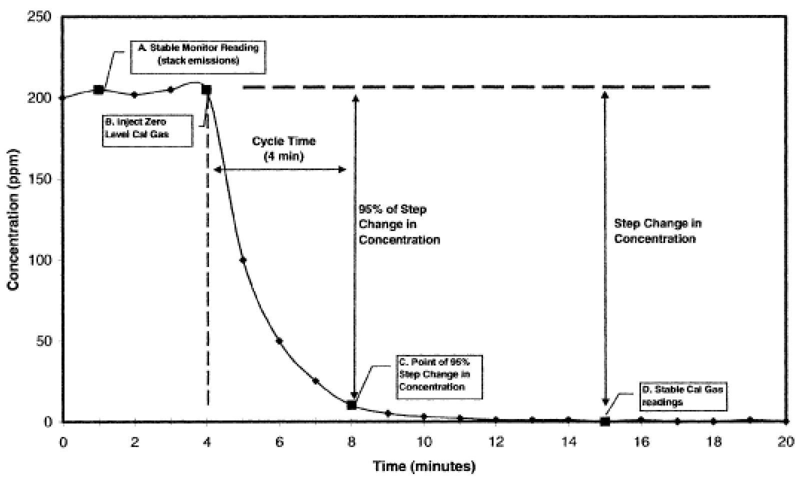
Figure 6b. Downscale Cycle Time Test



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A. To determine the upscale cycle time (Figure 6a), measure the flue gas emissions until the response stabilizes. Record the stabilized value (see section 6.4 of this appendix for the stability criteria).

B. Inject a high-level calibration gas into the port leading to the calibration cell or thimble (Point B). Allow the analyzer to stabilize. Record the stabilized value.

C. Determine the step change. The step change is equal to the difference between the final stable calibration gas value (Point D) and the stabilized stack emissions value (Point A).

D. Take 95% of the step change value and add the result to the stabilized stack emissions value (Point A). Determine the time at which 95% of the step change occurred (Point C).

E. Calculate the upscale cycle time by subtracting the time at which the calibration gas was injected (Point B) from the time at which 95% of the step change occurred (Point C). In this example, upscale cycle time = (11−5) = 6 minutes.

F. To determine the downscale cycle time (Figure 6b) repeat the procedures above, except that a zero gas is injected when the flue gas emissions have stabilized, and 95% of the step change in concentration is subtracted from the stabilized stack emissions value.

G. Compare the upscale and downscale cycle time values. The longer of these two times is the cycle time for the analyzer.

EDITORIAL NOTE: For FEDERAL REGISTER citations affecting part 75, Appendix A, see the List of CFR Sections Affected, which appears in the Finding Aids section of the printed volume and at *www.govinfo.gov.*

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Appendix B to Part 75—Quality Assurance and Quality Control Procedures

1. Quality Assurance/Quality Control Program

Develop and implement a quality assurance/quality control (QA/QC) program for the continuous emission monitoring systems, excepted monitoring systems approved under appendix D or E to this part, and alternative monitoring systems under subpart E of this part, and their components. At a minimum, include in each QA/QC program a written plan that describes in detail (or that refers to separate documents containing) complete, step-by-step procedures and operations for each of the following activities. Upon request from regulatory authorities, the source shall make all procedures, maintenance records, and ancillary supporting documentation from the manufacturer (e.g., software coefficients and troubleshooting diagrams) available for review during an audit. Electronic storage of the information in the QA/QC plan is permissible, provided that the information can be made available in hardcopy upon request during an audit.

1.1 Requirements for All Monitoring Systems

1.1.1 Preventive Maintenance

Keep a written record of procedures needed to maintain the monitoring system in proper operating condition and a schedule for those procedures. This shall, at a minimum, include procedures specified by the manufacturers of the equipment and, if applicable, additional or alternate procedures developed for the equipment.

1.1.2 Recordkeeping and Reporting

Keep a written record describing procedures that will be used to implement the recordkeeping and reporting requirements in subparts E, F, and G and appendices D and E to this part, as applicable.

1.1.3 Maintenance Records

Keep a record of all testing, maintenance, or repair activities performed on any monitoring system or component in a location and format suitable for inspection. A maintenance log may be used for this purpose. The following records should be maintained: date, time, and description of any testing, adjustment, repair, replacement, or preventive maintenance action performed on any monitoring system and records of any corrective actions associated with a monitor's outage period. Additionally, any adjustment that recharacterizes a system's ability to record and report emissions data must be recorded (e.g., changing of flow monitor or moisture monitoring system polynomial coefficients, K factors or mathematical algorithms, changing of temperature and pressure coefficients and dilution ratio settings), and a written explanation of the procedures used to make the adjustment(s) shall be kept.

1.1.4 The provisions in section 6.1.2 of appendix A to this part shall apply to the annual RATAs described in §75.74(c)(2)(ii) and to the semiannual and annual RATAs described in section 2.3 of this appendix.

1.2 Specific Requirements for Continuous Emissions Monitoring Systems

1.2.1 Calibration Error Test and Linearity Check Procedures

Keep a written record of the procedures used for daily calibration error tests and linearity checks (e.g., how gases are to be injected, adjustments of flow rates and pressure, introduction of reference values, length of time for injection of calibration gases, steps for obtaining calibration error or error in linearity, determination of interferences, and when calibration adjustments should be made). Identify any calibration error test and linearity check procedures specific to the continuous emission monitoring system that vary from the procedures in appendix A to this part.

1.2.2 Calibration and Linearity Adjustments

Explain how each component of the continuous emission monitoring system will be adjusted to provide correct responses to calibration gases, reference values, and/or indications of interference both initially and after repairs or corrective action. Identify equations, conversion factors and other factors affecting calibration of each continuous emission monitoring system.

1.2.3 Relative Accuracy Test Audit Procedures

Keep a written record of procedures and details peculiar to the installed continuous emission monitoring systems that are to be used for relative accuracy test audits, such as sampling and analysis methods.

1.2.4 Parametric Monitoring for Units With Add-on Emission Controls

The owner or operator shall keep a written (or electronic) record including a list of operating parameters for the add-on SO_2 or NO_X emission controls, including parameters in §75.55(b) or §75.58(b), as applicable, and the range of each operating parameter that indicates the add-on emission controls are operating properly. The owner or operator shall keep a written (or electronic) record of the parametric monitoring data during each SO_2 or NO_X missing data period.

1.3 Specific Requirements for Excepted Systems Approved Under Appendices D and E

1.3.1 Fuel Flowmeter Accuracy Test Procedures

Keep a written record of the specific fuel flowmeter accuracy test procedures. These may include: standard methods or specifications listed in and of appendix D to this part and incorporated by reference under §75.6; the procedures of sections 2.1.5.2 or 2.1.7 of appendix D to this part; or other methods approved by the Administrator through the petition process of §75.66(c).

1.3.2 Transducer or Transmitter Accuracy Test Procedures

Keep a written record of the procedures for testing the accuracy of transducers or transmitters of an orifice-, nozzle-, or venturi-type fuel flowmeter under section 2.1.6 of appendix D to this part. These procedures should include a description of equipment used, steps in testing, and frequency of testing.

1.3.3 Fuel Flowmeter, Transducer, or Transmitter Calibration and Maintenance Records

Keep a record of adjustments, maintenance, or repairs performed on the fuel flowmeter monitoring system. Keep records of the data and results for fuel flowmeter accuracy tests and transducer accuracy tests, consistent with appendix D to this part.

1.3.4 Primary Element Inspection Procedures

Keep a written record of the standard operating procedures for inspection of the primary element (i.e., orifice, venturi, or nozzle) of an orifice-, venturi-, or nozzle-type fuel flowmeter. Examples of the types of information to be included are: what to examine on the primary element; how to identify if there is corrosion sufficient to affect the accuracy of the primary element; and what inspection tools (e.g., baroscope), if any, are used.

1.3.5 Fuel Sampling Method and Sample Retention

Keep a written record of the standard procedures used to perform fuel sampling, either by utility personnel or by fuel supply company personnel. These procedures should specify the portion of the ASTM method used, as incorporated by reference under §75.6, or other methods approved by the Administrator through the petition process of §75.66(c). These procedures should describe safeguards for ensuring the availability of an oil sample (e.g., procedure and location for splitting samples, procedure for maintaining sample splits on site, and procedure for transmitting samples to an analytical laboratory). These procedures should identify the ASTM analytical methods used to analyze sulfur content, gross calorific value, and density, as incorporated by reference under §75.6, or other methods approved by the Administrator through the petition process of §75.66(c).

1.3.6 Appendix E Monitoring System Quality Assurance Information

Identify the recommended range of quality assurance- and quality control-related operating parameters. Keep records of these operating parameters for each hour of unit operation (i.e., fuel combustion). Keep a written record of the procedures used to perform NO_X emission rate testing. Keep a copy of all data and results from the initial and from the most recent NO_X emission rate testing, including the values of quality assurance parameters specified in section 2.3 of appendix E to this part.

1.4 Requirements for Alternative Systems Approved Under Subpart E

1.4.1 Daily Quality Assurance Tests

Explain how the daily assessment procedures specific to the alternative monitoring system are to be performed.

1.4.2 Daily Quality Assurance Test Adjustments

Explain how each component of the alternative monitoring system will be adjusted in response to the results of the daily assessments.

1.4.3 Relative Accuracy Test Audit Procedures

Keep a written record of procedures and details peculiar to the installed alternative monitoring system that are to be used for relative accuracy test audits, such as sampling and analysis methods.

2. Frequency of Testing

A summary chart showing each quality assurance test and the frequency at which each test is required is located at the end of this appendix in Figure 1.

2.1 Daily Assessments

Perform the following daily assessments to quality-assure the hourly data recorded by the monitoring systems during each period of unit operation, or, for a bypass stack or duct, each period in which emissions pass through the bypass stack or duct. These requirements are effective as of the date when the monitor or continuous emission monitoring system completes certification testing.

2.1.1 Calibration Error Test

Except as provided in section 2.1.1.2 of this appendix, perform the daily calibration error test of each gas monitoring system (including moisture monitoring systems consisting of wet- and dry-basis O_2 analyzers) according to the procedures in section 6.3.1 of appendix A to this part, and perform the daily calibration error test of each flow monitoring system according to the procedure in section 6.3.2 of appendix A to this part. When two measurement ranges (low and high) are required for a particular parameter, perform sufficient calibration error tests on each range to validate the data recorded on that range, according to the criteria in section 2.1.5 of this appendix.

2.1.1.1 On-line Daily Calibration Error Tests. Except as provided in section 2.1.1.2 of this appendix, all daily calibration error tests must be performed while the unit is in operation at normal, stable conditions (i.e. “on-line”).

2.1.1.2 Off-line Daily Calibration Error Tests. Daily calibrations may be performed while the unit is not operating (i.e., “off-line”) and may be used to validate data for a monitoring system that meets the following conditions:

(1) An initial demonstration test of the monitoring system is successfully completed and the results are reported in the quarterly report required under §75.64 of this part. The initial demonstration test, hereafter called the “off-line calibration demonstration”, consists of an off-line calibration error test followed by an on-line calibration error test. Both the off-line and on-line portions of the off-line calibration demonstration must meet the calibration error performance specification in section 3.1 of appendix A of this part. Upon completion of the off-line portion of the demonstration, the zero and upscale monitor responses may be adjusted, but only toward the true values of the calibration gases or reference signals used to perform the test and only in accordance with the routine calibration adjustment procedures specified in the quality control program required under section 1 of appendix B to this part. Once these adjustments are made, no further adjustments may be made to the monitoring system until after completion of the on-line portion of the off-line calibration demonstration. Within 26 clock hours of the completion hour of the off-line portion of the demonstration, the monitoring system must successfully complete the first attempted calibration error test, i.e., the on-line portion of the demonstration.

(2) For each monitoring system that has passed the off-line calibration demonstration, off-line calibration error tests may be used on a limited basis to validate data, in accordance with paragraph (2) in section 2.1.5.1 of this appendix.

2.1.2 Daily Flow Interference Check

Perform the daily flow monitor interference checks specified in section 2.2.2.2 of appendix A of this part while the unit is in operation at normal, stable conditions.

2.1.3 Additional Calibration Error Tests and Calibration Adjustments

(a) In addition to the daily calibration error tests required under section 2.1.1 of this appendix, a calibration error test of a monitor shall be performed in accordance with section 2.1.1 of this appendix, as follows: whenever a daily calibration error test is failed; whenever a monitoring system is returned to service following repair or corrective maintenance that could affect the monitor's ability to accurately measure and record emissions data; or after making certain calibration adjustments, as described in this section. Except in the case of the routine calibration adjustments described in this section, data from the monitor are considered invalid until the required additional calibration error test has been successfully completed.

(b) Routine calibration adjustments of a monitor are permitted after any successful calibration error test. These routine adjustments shall be made so as to bring the monitor readings as close as practicable to the known tag values of the calibration gases or to the actual value of the flow monitor reference signals. An additional calibration error test is required following routine calibration adjustments where the monitor's calibration has been physically adjusted (e.g., by turning a potentiometer) to verify that the adjustments have been made properly. An additional calibration error test is not required, however, if the routine calibration adjustments are made by means of a mathematical algorithm programmed into the data acquisition and handling system. The EPA recommends that routine calibration adjustments be made, at a minimum, whenever the daily calibration error exceeds the limits of the applicable performance specification in appendix A to this part for the pollutant concentration monitor, CO_2 or O_2 monitor, or flow monitor.

(c) Additional (non-routine) calibration adjustments of a monitor are permitted prior to (but not during) linearity checks and RATAs and at other times, provided that an appropriate technical justification is included in the quality control program required under section 1 of this appendix. The allowable non-routine adjustments are as follows. The owner or operator may physically adjust the calibration of a monitor (e.g., by means of a potentiometer), provided that the post-adjustment zero and upscale responses of the monitor are within the performance specifications of the instrument given in section 3.1 of appendix A to this part. An additional calibration error test is required following such adjustments to verify that the monitor is operating within the performance specifications at both the zero and upscale calibration levels.

2.1.4 Data Validation

(a) An out-of-control period occurs when the calibration error of an SO_2 or NO_X pollutant concentration monitor exceeds 5.0 percent of the span value, when the calibration error of a CO_2 or O_2 monitor (including O_2 monitors used to measure CO_2 emissions or percent moisture) exceeds 1.0 percent O_2 or CO_2, or when the calibration error of a flow monitor exceeds 6.0 percent of the span value, which is twice the applicable specification of appendix A to this part. Notwithstanding, a differential pressure-type flow monitor for which the calibration error exceeds 6.0 percent of the span value shall not be considered out-of-control if |R-A|, the absolute value of the difference between the monitor response and the reference value in Equation A-6 of appendix A to this part, is <0.02 inches of water. In addition, an SO_2 or NO_X monitor for which the calibration error exceeds 5.0 percent of the span value shall not be considered out-of-control if |R-A| in Equation A-6 does not exceed 5.0 ppm (for span values ≤50 ppm), or if |R-A|; does not exceed 10.0 ppm (for span values >50 ppm, but ≤200 ppm). The out-of-control period begins upon failure of the calibration error test and ends upon completion of a successful calibration error test. Note, that if a failed calibration, corrective action, and successful calibration error test occur within the same hour, emission data for that hour recorded by the monitor after the successful calibration error test may be used for reporting purposes, provided that two or more valid readings are obtained as required by §75.10. A NO_X-diluent CEMS is considered out-of-control if the calibration error of either component monitor exceeds twice the applicable performance specification in appendix A to this part. Emission data shall not be reported from an out-of-control monitor.

(b) An out-of-control period also occurs whenever interference of a flow monitor is identified. The out-of-control period begins with the hour of completion of the failed interference check and ends with the hour of completion of an interference check that is passed.

(c) The results of any certification, recertification, diagnostic, or quality assurance test required under this part may not be used to validate the emissions data required under this part, if the test is performed using EPA Protocol gas from a production site that is not participating in the PGVP, except as provided in §75.21(g)(7) or if the cylinder(s) are analyzed by an independent laboratory and shown to meet the requirements of section 5.1.4(b) of appendix A to this part.

2.1.5 Quality Assurance of Data With Respect to Daily Assessments

When a monitoring system passes a daily assessment (i.e., daily calibration error test or daily flow interference check), data from that monitoring system are prospectively validated for 26 clock hours (i.e., 24 hours plus a 2-hour grace period) beginning with the hour in which the test is passed, unless another assessment (i.e. a daily calibration error test, an interference check of a flow monitor, a quarterly linearity check, a quarterly leak check, or a relative accuracy test audit) is failed within the 26-hour period.

2.1.5.1 Data Invalidation with Respect to Daily Assessments. The following specific rules apply to the invalidation of data with respect to daily assessments:

(1) Data from a monitoring system are invalid, beginning with the first hour following the expiration of a 26-hour data validation period or beginning with the first hour following the expiration of an 8-hour start-up grace period (as provided under section 2.1.5.2 of this appendix), if the required subsequent daily assessment has not been conducted.

(2) For a monitor that has passed the off-line calibration demonstration, a combination of on-line and off-line calibration error tests may be used to validate data from the monitor, as follows. For a particular unit (or stack) operating hour, data from a monitor may be validated using a successful off-line calibration error test if: (a) An on-line calibration error test has been passed within the previous 26 unit (or stack) operating hours; and (b) the 26 clock hour data validation window for the off-line calibration error test has not expired. If either of these conditions is not met, then the data from the monitor are invalid with respect to the daily calibration error test requirement. Data from the monitor shall remain invalid until the appropriate on-line or off-line calibration error test is successfully completed so that both conditions (a) and (b) are met.

(3) For units with two measurement ranges (low and high) for a particular parameter, when separate analyzers are used for the low and high ranges, a failed or expired calibration on one of the ranges does not affect the quality-assured data status on the other range. For a dual-range analyzer (i.e., a single analyzer with two measurement scales), a failed calibration error test on either the low or high scale results in an out-of-control period for the monitor. Data from the monitor remain invalid until corrective actions are taken and “hands-off” calibration error tests have been passed on both ranges. However, if the most

recent calibration error test on the high scale was passed but has expired, while the low scale is up-to-date on its calibration error test requirements (or vice-versa), the expired calibration error test does not affect the quality-assured status of the data recorded on the other scale.

2.1.5.2 Daily Assessment Start-Up Grace Period. For the purpose of quality assuring data with respect to a daily assessment (i.e. a daily calibration error test or a flow interference check), a start-up grace period may apply when a unit begins to operate after a period of non-operation. The start-up grace period for a daily calibration error test is independent of the start-up grace period for a daily flow interference check. To qualify for a start-up grace period for a daily assessment, there are two requirements:

(1) The unit must have resumed operation after being in outage for 1 or more hours (i.e., the unit must be in a start-up condition) as evidenced by a change in unit operating time from zero in one clock hour to an operating time greater than zero in the next clock hour.

(2) For the monitoring system to be used to validate data during the grace period, the previous daily assessment of the same kind must have been passed on-line within 26 clock hours prior to the last hour in which the unit operated before the outage. In addition, the monitoring system must be in-control with respect to quarterly and semi-annual or annual assessments.

If both of the above conditions are met, then a start-up grace period of up to 8 clock hours applies, beginning with the first hour of unit operation following the outage. During the start-up grace period, data generated by the monitoring system are considered quality-assured. For each monitoring system, a start-up grace period for a calibration error test or flow interference check ends when either: (1) a daily assessment of the same kind (i.e., calibration error test or flow interference check) is performed; or (2) 8 clock hours have elapsed (starting with the first hour of unit operation following the outage), whichever occurs first.

2.1.6 Data Recording

Record and tabulate all calibration error test data according to month, day, clock-hour, and magnitude in either ppm, percent volume, or scfh. Program monitors that automatically adjust data to the corrected calibration values (e.g., microprocessor control) to record either: (1) The unadjusted concentration or flow rate measured in the calibration error test prior to resetting the calibration, or (2) the magnitude of any adjustment. Record the following applicable flow monitor interference check data: (1) Sample line/sensing port pluggage, and (2) malfunction of each RTD, transceiver, or equivalent.

2.2 Quarterly Assessments

For each primary and redundant backup monitor or monitoring system, perform the following quarterly assessments. This requirement is applies as of the calendar quarter following the calendar quarter in which the monitor or continuous emission monitoring system is provisionally certified.

2.2.1 Linearity Check

Unless a particular monitor (or monitoring range) is exempted under this paragraph or under section 6.2 of appendix A to this part, perform a linearity check, in accordance with the procedures in section 6.2 of appendix A to this part, for each primary and redundant backup SO_2, and NOx pollutant concentration monitor and each primary and redundant backup CO_2 or O_2 monitor (including O_2 monitors used to measure CO_2 emissions or to continuously monitor moisture) at least once during each QA operating quarter, as defined in §72.2 of this chapter. For units using both a low and high span value, a linearity check is required only on the range(s) used to record and report emission data during the QA operating quarter. Conduct the linearity checks no less than 30 days apart, to the extent practicable. The data validation procedures in section 2.2.3(e) of this appendix shall be followed.

2.2.2 Leak Check

For differential pressure flow monitors, perform a leak check of all sample lines (a manual check is acceptable) at least once during each QA operating quarter. For this test, the unit does not have to be in operation. Conduct the leak checks no less than 30 days apart, to the extent practicable. If a leak check is failed, follow the applicable data validation procedures in section 2.2.3(g) of this appendix.

2.2.3 Data Validation

(a) A linearity check shall not be commenced if the monitoring system is operating out-of-control with respect to any of the daily or semiannual quality assurance assessments required by sections 2.1 and 2.3 of this appendix or with respect to the additional calibration error test requirements in section 2.1.3 of this appendix.

(b) Each required linearity check shall be done according to paragraph (b)(1), (b)(2) or (b)(3) of this section:

(1) The linearity check may be done "cold," i.e., with no corrective maintenance, repair, calibration adjustments, re-linearization or reprogramming of the monitor prior to the test.

(2) The linearity check may be done after performing only the routine or non-routine calibration adjustments described in section 2.1.3 of this appendix at the various calibration gas levels (zero, low, mid or high), but no other corrective maintenance, repair, re-linearization or reprogramming of the monitor. Trial gas injection runs may be performed after the calibration adjustments and additional adjustments within the allowable limits in section 2.1.3 of this appendix may be made prior to the linearity check, as necessary, to optimize the performance of the monitor. The trial gas injections need not be reported, provided that they meet the specification for trial gas injections in §75.20(b)(3)(vii)(E)(*1*). However, if, for any trial injection, the specification in §75.20(b)(3)(vii)(E)(*1*) is not met, the trial injection shall be counted as an aborted linearity check.

(3) The linearity check may be done after repair, corrective maintenance or reprogramming of the monitor. In this case, the monitor shall be considered out-of-control from the hour in which the repair, corrective maintenance or reprogramming is commenced until the linearity check has been passed. Alternatively, the data validation procedures and associated timelines in §§75.20(b)(3)(ii) through (ix) may be followed upon completion of the necessary repair, corrective maintenance, or reprogramming. If the procedures in §75.20(b)(3) are used, the words "quality assurance" apply instead of the word "recertification".

(c) Once a linearity check has been commenced, the test shall be done hands-off. That is, no adjustments of the monitor are permitted during the linearity test period, other than the routine calibration adjustments following daily calibration error tests, as described in section 2.1.3 of this appendix. If a routine daily calibration error test is performed and passed just prior to a linearity test (or during a linearity test period) and a mathematical correction factor is automatically applied by the DAHS, the correction factor shall be applied to all subsequent data recorded by the monitor, including the linearity test data.

(d) If a daily calibration error test is failed during a linearity test period, prior to completing the test, the linearity test must be repeated. Data from the monitor are invalidated prospectively from the hour of the failed calibration error test until the hour of completion of a subsequent successful calibration error test. The linearity test shall not be commenced until the monitor has successfully completed a calibration error test.

(e) An out-of-control period occurs when a linearity test is failed (i.e., when the error in linearity at any of the three concentrations in the quarterly linearity check (or any of the six concentrations, when both ranges of a single analyzer with a dual range are tested) exceeds the applicable specification in section 3.2 of appendix A to this part) or when a linearity test is aborted due to a problem with the monitor or monitoring system. For a NO_X-diluent continuous emission monitoring system, the system is considered out-of-control if either of the component monitors exceeds the applicable specification in section 3.2 of appendix A to this part or if the linearity test of either component is aborted due to a problem with the monitor. The out-of-control period begins with the hour of the failed or aborted linearity check and ends with the hour of completion of a satisfactory linearity check following corrective action and/or monitor repair, unless the option in paragraph (b)(3) of this section to use the data validation procedures and associated timelines in §75.20(b)(3)(ii) through (ix) has been selected, in which case the beginning and end of the out-of-control period shall be determined in accordance with §§75.20(b)(3)(vii)(A) and (B). For a dual-range analyzer, "hands-off" linearity checks must be passed on both measurement scales to end the out-of-control period. Note that a monitor shall not be considered out-of-control when a linearity test is aborted for a reason unrelated to the monitor's performance (e.g., a forced unit outage).

(f) No more than four successive calendar quarters shall elapse after the quarter in which a linearity check of a monitor or monitoring system (or range of a monitor or monitoring system) was last performed without a subsequent linearity test having been conducted. If a linearity test has not been completed by the end of the fourth calendar quarter since the last linearity test, then the linearity test must be completed within a 168 unit operating hour or stack operating hour "grace period" (as provided in section 2.2.4 of this appendix) following the end of the fourth successive elapsed calendar quarter, or data from the CEMS (or range) will become invalid.

(g) An out-of-control period also occurs when a flow monitor sample line leak is detected. The out-of-control period begins with the hour of the failed leak check and ends with the hour of a satisfactory leak check following corrective action.

(h) For each monitoring system, report the results of all completed and partial linearity tests that affect data validation (i.e., all completed, passed linearity checks; all completed, failed linearity checks; and all linearity checks aborted due to a problem with the monitor, including trial gas injections counted as failed test attempts under paragraph (b)(2) of this section or under §75.20(b)(3)(vii)(F)), in the quarterly report required under §75.64. Note that linearity attempts which are aborted or invalidated due to problems with the reference calibration gases or due to operational problems with the affected unit(s) need not be reported. Such partial tests do not affect the validation status of emission data recorded by the monitor. A record of all linearity tests, trial gas injections and test attempts (whether reported or not) must be kept on-site as part of the official test log for each monitoring system.

(i) The results of any certification, recertification, diagnostic, or quality assurance test required under this part may not be used to validate the emissions data required under this part, if the test is performed using EPA Protocol gas that was not from an EPA Protocol gas production site participating in the PGVP on the date the gas was procured either by the tester or by a reseller that sold to the tester the unaltered EPA Protocol gas, except as provided in §75.21(g)(7) or if the cylinder(s) are analyzed by an independent laboratory and shown to meet the requirements of section 5.1.4(b) of appendix A to this part.

2.2.4 Linearity and Leak Check Grace Period

(a) When a required linearity test or flow monitor leak check has not been completed by the end of the QA operating quarter in which it is due or if, due to infrequent operation of a unit or infrequent use of a required high range of a monitor or monitoring system, four successive calendar quarters have elapsed after the quarter in which a linearity check of a monitor or monitoring system (or range) was last performed without a subsequent linearity test having been done, the owner or operator has a grace period of 168 consecutive unit operating hours, as defined in §72.2 of this chapter (or, for monitors installed on common stacks or bypass stacks, 168 consecutive stack operating hours, as defined in §72.2 of this chapter) in which to perform a linearity test or leak check of that monitor or monitoring system (or range). The grace period begins with the first unit or stack operating hour following the calendar quarter in which the linearity test was due. Data validation during a linearity or leak check grace period shall be done in accordance with the applicable provisions in section 2.2.3 of this appendix.

(b) If, at the end of the 168 unit (or stack) operating hour grace period, the required linearity test or leak check has not been completed, data from the monitoring system (or range) shall be invalid, beginning with the first unit operating hour following the expiration of the grace period. Data from the monitoring system (or range) remain invalid until the hour of completion of a subsequent successful hands-off linearity test or leak check of the monitor or monitoring system (or range). Note that when a linearity test or a leak check is conducted within a grace period for the purpose of satisfying the linearity test or leak check requirement from a previous QA operating quarter, the results of that linearity test or leak check may only be used to meet the linearity check or leak check requirement of the previous quarter, not the quarter in which the missed linearity test or leak check is completed.

2.2.5 Flow-to-Load Ratio or Gross Heat Rate Evaluation

(a) *Applicability and methodology.* Unless exempted from the flow-to-load ratio test under section 7.8 of appendix A to this part, the owner or operator shall, for each flow rate monitoring system installed on each unit, common stack or multiple stack, evaluate the flow-to-load ratio quarterly, i.e., for each QA operating quarter (as defined in §72.2 of this chapter). At the end of each QA operating quarter, the owner or operator shall use Equation B-1 to calculate the flow-to-load ratio for every hour during the quarter in which: the unit (or combination of units, for a common stack) operated within ±10.0 percent of L_{avg}, the average load during the most recent normal-load flow RATA; and a quality-assured hourly average flow rate was obtained with a certified flow rate monitor. Alternatively, for the reasons stated in paragraphs (c)(1) through (c)(6) of this section, the owner or operator may exclude from the data analysis certain hours within ±10.0 percent of L_{avg} and may calculate R_h values for only the remaining hours.

$$R_h = \frac{Q_h}{L_h} \times 10^{-5} \qquad (Eq.\ B\text{-}1)$$

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Where:

R_h = Hourly value of the flow-to-load ratio, scfh/megawatts, scfh/1000 lb/hr of steam, or scfh/(mmBtu/hr thermal output).

Q_h = Hourly stack gas volumetric flow rate, as measured by the flow rate monitor, scfh.

L_h = Hourly unit load, megawatts, 1000 lb/hr of steam, or mmBtu/hr thermal output; must be within + 10.0 percent of L_{avg} during the most recent normal-load flow RATA.

(1) In Equation B-1, the owner or operator may use either bias-adjusted flow rates or unadjusted flow rates, provided that all of the ratios are calculated the same way. For a common stack, L_h shall be the sum of the hourly operating loads of all units that discharge through the stack. For a unit that discharges its emissions through multiple stacks or that monitors its emissions in multiple breechings, Q_h will be either the combined hourly volumetric flow rate for all of the stacks or ducts (if the test is done on a unit basis) or the hourly flow rate through each stack individually (if the test is performed separately for each stack). For a unit with a multiple stack discharge configuration consisting of a main stack and a bypass stack, each of which has a certified flow monitor (e.g., a unit with a wet SO_2 scrubber), calculate the hourly flow-to-load ratios separately for each stack. Round off each value of R_h to two decimal places.

(2) Alternatively, the owner or operator may calculate the hourly gross heat rates (GHR) in lieu of the hourly flow-to-load ratios. The hourly GHR shall be determined only for those hours in which quality-assured flow rate data and diluent gas (CO_2 or O_2) concentration data are both available from a certified monitor or monitoring system or reference method. If this option is selected, calculate each hourly GHR value as follows:

$$(GHR)_h = \frac{(Heat\ Input)_h}{L_h} \times 1000 \qquad (Eq.\ B\text{-}1a)$$

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where:

$(GHR)_h$ = Hourly value of the gross heat rate, Btu/kwh, Btu/lb steam load, or 1000 mmBtu heat input/mmBtu thermal output.

$(Heat\ Input)_h$ = Hourly heat input, as determined from the quality-assured flow rate and diluent data, using the applicable equation in appendix F to this part, mmBtu/hr.

L_h = Hourly unit load, megawatts, 1000 lb/hr of steam, or mmBtu/hr thermal output; must be within + 10.0 percent of L_{avg} during the most recent normal-load flow RATA.

(3) In Equation B-1a, the owner or operator may either use bias-adjusted flow rates or unadjusted flow rates in the calculation of $(Heat\ Input)_h$, provided that all of the heat input rate values are determined in the same manner.

(4) The owner or operator shall evaluate the calculated hourly flow-to-load ratios (or gross heat rates) as follows. A separate data analysis shall be performed for each primary and each redundant backup flow rate monitor used to record and report data during the quarter. Each analysis shall be based on a minimum of 168 acceptable recorded hourly average flow rates (i.e., at loads within ±10 percent of L_{avg}). When two RATA load levels are designated as normal, the analysis shall be performed at the higher load level, unless there are fewer than 168 acceptable data points available at that load level, in which case the analysis shall be performed at the lower load level. If, for a particular flow monitor, fewer than 168 acceptable hourly flow-to-load ratios (or GHR values) are available at any of the load levels designated as normal, a flow-to-load (or GHR) evaluation is not required for that monitor for that calendar quarter.

(5) For each flow monitor, use Equation B-2 in this appendix to calculate E_h, the absolute percentage difference between each hourly R_h value and R_{ref}, the reference value of the flow-to-load ratio, as determined in accordance with section 7.7 of appendix A to this part. Note that R_{ref} shall always be based upon the most recent normal-load RATA, even if that RATA was performed in the calendar quarter being evaluated.

$$E_h = \frac{|R_{ref} - R_h|}{R_{ref}} \times 100 \qquad (Eq.\ B\text{-}2)$$

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where:

E_h = Absolute percentage difference between the hourly average flow-to-load ratio and the reference value of the flow-to-load ratio at normal load.

R_h = The hourly average flow-to-load ratio, for each flow rate recorded at a load level within ±10.0 percent of L_{avg}.

R_{ref} = The reference value of the flow-to-load ratio from the most recent normal-load flow RATA, determined in accordance with section 7.7 of appendix A to this part.

(6) Equation B-2 shall be used in a consistent manner. That is, use R_{ref} and R_h if the flow-to-load ratio is being evaluated, and use $(GHR)_{ref}$ and $(GHR)_h$ if the gross heat rate is being evaluated. Finally, calculate E_f, the arithmetic average of all of the hourly E_h values. The owner or operator shall report the results of each quarterly flow-to-load (or gross heat rate) evaluation, as determined from Equation B-2, in the electronic quarterly report required under §75.64.

(b) *Acceptable results.* The results of a quarterly flow-to-load (or gross heat rate) evaluation are acceptable, and no further action is required, if the calculated value of E_f is less than or equal to: (1) 15.0 percent, if L_{avg} for the most recent normal-load flow RATA is ≥60 megawatts (or ≥500 klb/hr of steam) and if unadjusted flow rates were used in the calculations; or (2) 10.0 percent, if L_{avg} for the most recent normal-load flow RATA is ≥60 megawatts (or ≥500 klb/hr of steam) and if bias-adjusted flow rates were used in the calculations; or (3) 20.0 percent, if L_{avg} for the most recent normal-load flow RATA is <60 megawatts (or <500 klb/hr of steam) and if unadjusted flow rates were used in the calculations; or (4) 15.0 percent, if L_{avg} for the most recent normal-load flow RATA is <60 megawatts (or <500 klb/hr of steam) and if bias-adjusted flow rates were used in the calculations. If E_f is above these limits, the owner or operator shall either: implement Option 1 in section 2.2.5.1 of this appendix; or perform a RATA in accordance with Option 2 in section 2.2.5.2 of this appendix; or re-examine the hourly data used for the flow-to-load or GHR analysis and recalculate E_f, after excluding all non-representative hourly flow rates. If E_f is above these limits, the owner or operator shall either: implement Option 1 in section 2.2.5.1 of this appendix; perform a RATA in accordance with

Option 2 in section 2.2.5.2 of this appendix; or (if applicable) re-examine the hourly data used for the flow-to-load or GHR analysis and recalculate E_f, after excluding all non-representative hourly flow rates, as provided in paragraph (c) of this section.

(c) *Recalculation of E_f*. If the owner or operator did not exclude any hours within ±10 percent of L_{avg} from the original data analysis and chooses to recalculate E_f, the flow rates for the following hours are considered non-representative and may be excluded from the data analysis:

(1) Any hour in which the type of fuel combusted was different from the fuel burned during the most recent normal-load RATA. For purposes of this determination, the type of fuel is different if the fuel is in a different state of matter (i.e., solid, liquid, or gas) than is the fuel burned during the RATA or if the fuel is a different classification of coal (e.g., bituminous versus sub-bituminous). Also, for units that co-fire different types of fuels, if the reference RATA was done while co-firing, then hours in which a single fuel was combusted may be excluded from the data analysis as different fuel hours (and vice-versa for co-fired hours, if the reference RATA was done while combusting only one type of fuel);

(2) For a unit that is equipped with an SO_2 scrubber and which always discharges its flue gases to the atmosphere through a single stack, any hour in which the SO_2 scrubber was bypassed;

(3) Any hour in which "ramping" occurred, i.e., the hourly load differed by more than ±15.0 percent from the load during the preceding hour or the subsequent hour;

(4) For a unit with a multiple stack discharge configuration consisting of a main stack and a bypass stack, any hour in which the flue gases were discharged through both stacks;

(5) If a normal-load flow RATA was performed and passed during the quarter being analyzed, any hour prior to completion of that RATA; and

(6) If a problem with the accuracy of the flow monitor was discovered during the quarter and was corrected (as evidenced by passing the abbreviated flow-to-load test in section 2.2.5.3 of this appendix), any hour prior to completion of the abbreviated flow-to-load test.

(7) After identifying and excluding all non-representative hourly data in accordance with paragraphs (c)(1) through (6) of this section, the owner or operator may analyze the remaining data a second time. At least 168 representative hourly ratios or GHR values must be available to perform the analysis; otherwise, the flow-to-load (or GHR) analysis is not required for that monitor for that calendar quarter.

(8) If, after re-analyzing the data, E_f meets the applicable limit in paragraph (b)(1), (b)(2), (b)(3), or (b)(4) of this section, no further action is required. If, however, E_f is still above the applicable limit, data from the monitor shall be declared out-of-control, beginning with the first unit operating hour following the quarter in which E_f exceeded the applicable limit. Alternatively, if a probationary calibration error test is performed and passed according to §75.20(b)(3)(ii), data from the monitor may be declared conditionally valid following the quarter in which E_f exceeded the applicable limit. The owner or operator shall then either implement Option 1 in section 2.2.5.1 of this appendix or Option 2 in section 2.2.5.2 of this appendix.

2.2.5.1 Option 1

Within 14 unit operating days of the end of the calendar quarter for which the E_f value is above the applicable limit, investigate and troubleshoot the applicable flow monitor(s). Evaluate the results of each investigation as follows:

(a) If the investigation fails to uncover a problem with the flow monitor, a RATA shall be performed in accordance with Option 2 in section 2.2.5.2 of this appendix.

(b) If a problem with the flow monitor is identified through the investigation (including the need to re-linearize the monitor by changing the polynomial coefficients or K factor(s)), data from the monitor are considered invalid back to the first unit operating hour after the end of the calendar quarter for which E_f was above the applicable limit. If the option to use conditional data validation was selected under section 2.2.5(c)(8) of this appendix, all conditionally valid data shall be invalidated, back to the first unit operating hour after the end of the calendar quarter for which E_f was above the applicable limit. Corrective actions shall be taken. All corrective actions (*e.g.,* non-routine maintenance, repairs, major component replacements, re-linearization of the monitor, etc.) shall be documented in the operation and maintenance records for the monitor. The owner or operator then shall either complete the abbreviated flow-to-load test in section 2.2.5.3 of this appendix, or, if the corrective action taken has required relinearization of the flow monitor, shall perform a 3-load RATA. The conditional data validation procedures in §75.20(b)(3) may be applied to the 3-load RATA.

2.2.5.2 Option 2

Perform a single-load RATA (at a load designated as normal under section 6.5.2.1 of appendix A to this part) of each flow monitor for which E_f is outside of the applicable limit. If the RATA is passed hands-off, in accordance with section 2.3.2(c) of this appendix, no further action is required and the out-of-control period for the monitor ends at the date and hour of completion of a successful RATA, unless the option to use conditional data validation was selected under section 2.2.5(c)(8) of this appendix. In that case, all conditionally valid data from the monitor are considered to be quality-assured, back to the first unit operating hour following the end of the calendar quarter for which the E_f value was above the applicable limit. If the RATA is failed, all data from the monitor shall be invalidated, back to the first unit operating hour following the end of the calendar quarter for which the E_f value was above the applicable limit. Data from the monitor remain invalid until the required RATA has been passed. Alternatively, following a failed RATA and corrective actions, the conditional data validation procedures of §75.20(b)(3) may be used until the RATA has been passed. If the corrective actions taken following the failed RATA included adjustment of the polynomial coefficients or K-factor(s) of the flow monitor, a 3-level RATA is required, except as otherwise specified in section 2.3.1.3 of this appendix.

2.2.5.3 Abbreviated Flow-to-Load Test

(a) The following abbreviated flow-to-load test may be performed after any documented repair, component replacement, or other corrective maintenance to a flow monitor (except for changes affecting the linearity of the flow monitor, such as adjusting the flow monitor coefficients or K factor(s)) to demonstrate that the repair, replacement, or other maintenance has not significantly affected the monitor's ability to accurately measure the stack gas volumetric flow rate. Data from the monitoring system are considered invalid from the hour of commencement of the repair, replacement, or maintenance until either the hour in which the abbraviated flow-to-load test is passed, or the hour in which a probationary calibration error test is passed following completion of the repair, replacement, or maintenance and any associated adjustments to the monitor. If the latter option is selected, the abbreviated flow-to-load test shall be completed within 168 unit operating hours of the probationary calibration error test (or, for peaking units, within 30 unit operating days, if that is less restrictive). Data from the monitor are considered to be conditionally valid (as defined in §72.2 of this chapter), beginning with the hour of the probationary calibration error test.

(b) Operate the unit(s) in such a way as to reproduce, as closely as practicable, the exact conditions at the time of the most recent normal-load flow RATA. To achieve this, it is recommended that the load be held constant to within ±10.0 percent of the average load during the RATA and that the diluent gas (CO_2 or O_2) concentration be maintained within ±0.5 percent CO_2 or O_2 of the average diluent concentration during the RATA. For common stacks, to the extent practicable, use the same combination of units and load levels that were used during the RATA. When the process parameters have been set, record a minimum of six and a maximum of 12 consecutive hourly average flow rates, using the flow monitor(s) for which E_f was outside the applicable limit. For peaking units, a minimum of three and a maximum of 12 consecutive hourly average flow rates are required. Also record the corresponding hourly load values and, if applicable, the hourly diluent gas concentrations. Calculate the flow-to-load ratio (or GHR) for each hour in the test hour period, using Equation B-1 or B-1a. Determine E_h for each hourly flow-to-load ratio (or GHR), using Equation B-2 of this appendix and then calculate E_f, the arithmetic average of the E_h values.

(c) The results of the abbreviated flow-to-load test shall be considered acceptable, and no further action is required if the value of E_f does not exceed the applicable limit specified in section 2.2.5 of this appendix. All conditionally valid data recorded by the flow monitor shall be considered quality-assured, beginning with the hour of the probationary calibration error test that preceded the abbreviated flow-to-load test (if applicable). However, if E_f is outside the applicable limit, all conditionally valid data recorded by the flow monitor (if applicable) shall be considered invalid back to the hour of the probationary calibration error test that preceded the abbreviated flow-to-load test, and a single-load RATA is required in accordance with section 2.2.5.2 of this appendix. If the flow monitor must be re-linearized, however, a 3-load RATA is required.

2.3 Semiannual and Annual Assessments

For each primary and redundant backup monitoring system, perform relative accuracy assessments either semiannually or annually, as specified in section 2.3.1.1 or 2.3.1.2 of this appendix, for the type of test and the performance achieved. This requirement applies as of the calendar quarter following the calendar quarter in which the monitoring system is provisionally certified. A summary chart showing the frequency with which a relative accuracy test audit must be performed, depending on the accuracy achieved, is located at the end of this appendix in Figure 2.

2.3.1 Relative Accuracy Test Audit (RATA)

2.3.1.1 Standard RATA Frequencies

(a) Except as otherwise specified in §75.21(a)(6) or (a)(7) or in section 2.3.1.2 of this appendix, perform relative accuracy test audits semiannually, *i.e.,* once every two successive QA operating quarters (as defined in §72.2 of this chapter) for each primary and redundant backup SO_2 pollutant concentration monitor, flow monitor, CO_2 emissions concentration monitor (including O_2 monitors used to determine CO_2 emissions), CO_2 or O_2 diluent monitor used to determine heat input, moisture monitoring system, NO_X concentration monitoring system, or NO_X-diluent CEMS. A calendar quarter that does not qualify as a QA operating quarter shall be excluded in determining the deadline for the next RATA. No more than eight successive calendar quarters shall elapse after the quarter in which a RATA was last performed without a subsequent RATA having been conducted. If a RATA has not been completed by the end of the eighth calendar quarter since the quarter of the last RATA, then the RATA must be completed within a 720 unit (or stack) operating hour grace period (as provided in section 2.3.3 of this appendix) following the end of the eighth successive elapsed calendar quarter, or data from the CEMS will become invalid.

(b) The relative accuracy test audit frequency of a CEMS may be reduced, as specified in section 2.3.1.2 of this appendix, for primary or redundant backup monitoring systems which qualify for less frequent testing. Perform all required RATAs in accordance with the applicable procedures and provisions in sections 6.5 through 6.5.2.2 of appendix A to this part and sections 2.3.1.3 and 2.3.1.4 of this appendix.

2.3.1.2 Reduced RATA Frequencies

Relative accuracy test audits of primary and redundant backup SO_2 pollutant concentration monitors, CO_2 pollutant concentration monitors (including O_2 monitors used to determine CO_2 emissions), CO_2 or O_2 diluent monitors used to determine heat input, moisture monitoring systems, NO_X concentration monitoring systems, flow monitors, NO_X-diluent monitoring systems or SO_2-diluent monitoring systems may be performed annually (i.e., once every four successive QA operating quarters, rather than once every two successive QA operating quarters) if any of the following conditions are met for the specific monitoring system involved:

(a) The relative accuracy during the audit of an SO_2 or CO_2 pollutant concentration monitor (including an O_2 pollutant monitor used to measure CO_2 using the procedures in appendix F to this part), or of a CO_2 or O_2 diluent monitor used to determine heat input, or of a NO_X concentration monitoring system, or of a NO_X-diluent monitoring system, or of an SO_2-diluent continuous emissions monitoring system is ≤7.5 percent;

(b) [Reserved]

(c) The relative accuracy during the audit of a flow monitor is ≤7.5 percent at each operating level tested;

(d) For low flow (≤10.0 fps, as measured by the reference method during the RATA) stacks/ducts, when the flow monitor fails to achieve a relative accuracy ≤7.5 percent during the audit, but the monitor mean value, calculated using Equation A-7 in appendix A to this part and converted back to an equivalent velocity in standard feet per second (fps), is within ±1.5 fps of the reference method mean value, converted to an equivalent velocity in fps;

(e) For low SO_2 or NO_X emitting units (average SO_2 or NO_X reference method concentrations ≤250 ppm) during the RATA, when an SO_2 pollutant concentration monitor or NO_X concentration monitoring system fails to achieve a relative accuracy ≤7.5 percent during the audit, but the monitor mean value from the RATA is within ±12 ppm of the reference method mean value;

(f) For units with low NO_X emission rates (average NO_X emission rate measured by the reference method during the RATA ≤0.200 lb/mmBtu), when a NO_X-diluent continuous emission monitoring system fails to achieve a relative accuracy ≤7.5 percent, but the monitoring system mean value from the RATA, calculated using Equation A-7 in appendix A to this part, is within ±0.015 lb/mmBtu of the reference method mean value;

(g) [Reserved]

(h) For a CO_2 or O_2 monitor, when the mean difference between the reference method values from the RATA and the corresponding monitor values is within ±0.7 percent CO_2 or O_2; and

(i) When the relative accuracy of a continuous moisture monitoring system is ≤7.5 percent or when the mean difference between the reference method values from the RATA and the corresponding monitoring system values is within ±1.0 percent H_2O.

2.3.1.3 RATA Load (or Operating) Levels and Additional RATA Requirements

(a) For SO_2 pollutant concentration monitors, CO_2 emissions concentration monitors (including O_2 monitors used to determine CO_2 emissions), CO_2 or O_2 diluent monitors used to determine heat input, NO_X concentration monitoring systems, and NO_X-diluent monitoring systems, the required semiannual or annual RATA tests shall be done at the load level (or operating level) designated as normal under section 6.5.2.1(d) of appendix A to this part. If two load levels (or operating levels) are designated as normal, the required RATA(s) may be done at either load level (or operating level).

(b) For flow monitors installed on peaking units and bypass stacks, and for flow monitors that qualify to perform only single-level RATAs under section 6.5.2(e) of appendix A to this part, all required semiannual or annual relative accuracy test audits shall be single-load (or single-level) audits at the normal load (or operating level), as defined in section 6.5.2.1(d) of appendix A to this part.

(c) For all other flow monitors, the RATAs shall be performed as follows:

(1) An annual 2-load (or 2-level) flow RATA shall be done at the two most frequently used load levels (or operating levels), as determined under section 6.5.2.1(d) of appendix A to this part, or (if applicable) at the operating levels determined under section 6.5.2(e) of appendix A to this part. Alternatively, a 3-load (or 3-level) flow RATA at the low, mid, and high load levels (or operating levels), as defined under section 6.5.2.1(b) of appendix A to this part, may be performed in lieu of the 2-load (or 2-level) annual RATA.

(2) If the flow monitor is on a semiannual RATA frequency, 2-load (or 2-level) flow RATAs and single-load (or single-level) flow RATAs at the normal load level (or normal operating level) may be performed alternately.

(3) A single-load (or single-level) annual flow RATA may be performed in lieu of the 2-load (or 2-level) RATA if the results of an historical load data analysis show that in the time period extending from the ending date of the last annual flow RATA to a date that is no more than 21 days prior to the date of the current annual flow RATA, the unit (or combination of units, for a common stack) has operated at a single load level (or operating level) (low, mid, or high), for ≥85.0 percent of the time. Alternatively, a flow monitor may qualify for a single-load (or single-level) RATA if the 85.0 percent criterion is met in the time period extending from the beginning of the quarter in which the last annual flow RATA was performed through the end of the calendar quarter preceding the quarter of current annual flow RATA.

(4) A 3-load (or 3-level) RATA, at the low-, mid-, and high-load levels (or operating levels), as determined under section 6.5.2.1 of appendix A to this part, shall be performed at least once every twenty consecutive calendar quarters, except for flow monitors that are exempted from 3-load (or 3-level) RATA testing under section 6.5.2(b) or 6.5.2(e) of appendix A to this part.

(5) A 3-load (or 3-level) RATA is required whenever a flow monitor is re-linearized, *i.e.,* when its polynomial coefficients or K factor(s) are changed, except for flow monitors that are exempted from 3-load (or 3-level) RATA testing under section 6.5.2(b) or 6.5.2(e) of appendix A to this part. For monitors so exempted under section 6.5.2(b), a single-load flow RATA is required. For monitors so exempted under section 6.5.2(e), either a single-level RATA or a 2-level RATA is required, depending on the number of operating levels documented in the monitoring plan for the unit.

(6) For all multi-level flow audits, the audit points at adjacent load levels or at adjacent operating levels (*e.g.,* mid and high) shall be separated by no less than 25.0 percent of the "range of operation," as defined in section 6.5.2.1 of appendix A to this part.

(d) A RATA of a moisture monitoring system shall be performed whenever the coefficient, K factor or mathematical algorithm determined under section 6.5.7 of appendix A to this part is changed.

2.3.1.4 Number of RATA Attempts

The owner or operator may perform as many RATA attempts as are necessary to achieve the desired relative accuracy test audit frequencies and/or bias adjustment factors. However, the data validation procedures in section 2.3.2 of this appendix must be followed.

2.3.2 Data Validation

(a) A RATA shall not commence if the monitoring system is operating out-of-control with respect to any of the daily and quarterly quality assurance assessments required by sections 2.1 and 2.2 of this appendix or with respect to the additional calibration error test requirements in section 2.1.3 of this appendix.

(b) Each required RATA shall be done according to paragraphs (b)(1), (b)(2) or (b)(3) of this section:

(1) The RATA may be done "cold," i.e., with no corrective maintenance, repair, calibration adjustments, re-linearization or reprogramming of the monitoring system prior to the test.

(2) The RATA may be done after performing only the routine or non-routine calibration adjustments described in section 2.1.3 of this appendix at the zero and/or upscale calibration gas levels, but no other corrective maintenance, repair, re-linearization or reprogramming of the monitoring system. Trial RATA runs may be performed after the calibration adjustments and additional adjustments within the allowable limits in section 2.1.3 of this appendix may be made prior to the RATA, as necessary, to optimize the performance of the CEMS. The trial RATA runs need not be reported, provided that they meet the specification for trial RATA runs in §75.20(b)(3)(vii)(E)(*2*). However, if, for any trial run, the specification in §75.20(b)(3)(vii)(E)(*2*) is not met, the trial run shall be counted as an aborted RATA attempt.

(3) The RATA may be done after repair, corrective maintenance, re-linearization or reprogramming of the monitoring system. In this case, the monitoring system shall be considered out-of-control from the hour in which the repair, corrective maintenance, re-linearization or reprogramming is commenced until the RATA has been passed. Alternatively, the data validation procedures and associated timelines in §§75.20(b)(3)(ii) through (ix) may be followed upon completion of the

necessary repair, corrective maintenance, re-linearization or reprogramming. If the procedures in §75.20(b)(3) are used, the words "quality assurance" apply instead of the word "recertification."

(c) Once a RATA is commenced, the test must be done hands-off. No adjustment of the monitor's calibration is permitted during the RATA test period, other than the routine calibration adjustments following daily calibration error tests, as described in section 2.1.3 of this appendix. If a routine daily calibration error test is performed and passed just prior to a RATA (or during a RATA test period) and a mathematical correction factor is automatically applied by the DAHS, the correction factor shall be applied to all subsequent data recorded by the monitor, including the RATA test data. For 2-level and 3-level flow monitor audits, no linearization or reprogramming of the monitor is permitted in between load levels.

(d) For single-load (or single-level) RATAs, if a daily calibration error test is failed during a RATA test period, prior to completing the test, the RATA must be repeated. Data from the monitor are invalidated prospectively from the hour of the failed calibration error test until the hour of completion of a subsequent successful calibration error test. The subsequent RATA shall not be commenced until the monitor has successfully passed a calibration error test in accordance with section 2.1.3 of this appendix. For multiple-load (or multiple-level) flow RATAs, each load level (or operating level) is treated as a separate RATA (*i.e.,* when a calibration error test is failed prior to completing the RATA at a particular load level (or operating level), only the RATA at that load level (or operating level) must be repeated; the results of any previously-passed RATA(s) at the other load level(s) (or operating level(s)) are unaffected, unless the monitor's polynomial coefficients or K-factor(s) must be changed to correct the problem that caused the calibration failure, in which case a subsequent 3-load (or 3-level) RATA is required), except as otherwise provided in section 2.3.1.3 (c)(5) of this appendix.

(e) For a RATA performed using the option in paragraph (b)(1) or (b)(2) of this section, if the RATA is failed (that is, if the relative accuracy exceeds the applicable specification in section 3.3 of appendix A to this part) or if the RATA is aborted prior to completion due to a problem with the CEMS, then the CEMS is out-of-control and all emission data from the CEMS are invalidated prospectively from the hour in which the RATA is failed or aborted. Data from the CEMS remain invalid until the hour of completion of a subsequent RATA that meets the applicable specification in section 3.3 of appendix A to this part. If the option in paragraph (b)(3) of this section to use the data validation procedures and associated timelines in §§75.20(b)(3)(ii) through(b)(3)(ix) has been selected, the beginning and end of the out-of-control period shall be determined in accordance with §75.20(b)(3)(vii)(A) and (B). Note that when a RATA is aborted for a reason other than monitoring system malfunction (*see* paragraph (h) of this section), this does not trigger an out-of-control period for the monitoring system.

(f) For a 2-level or 3-level flow RATA, if, at any load level (or operating level), a RATA is failed or aborted due to a problem with the flow monitor, the RATA at that load level (or operating level) must be repeated. The flow monitor is considered out-of-control and data from the monitor are invalidated from the hour in which the test is failed or aborted and remain invalid until the passing of a RATA at the failed load level (or operating level), unless the option in paragraph (b)(3) of this section to use the data validation procedures and associated timelines in §75.20(b)(3)(ii) through (b)(3)(ix) has been selected, in which case the beginning and end of the out-of-control period shall be determined in accordance with §75.20(b)(3)(vii)(A) and (B). Flow RATA(s) that were previously passed at the other load level(s) (or operating level(s)) do not have to be repeated unless the flow monitor must be re-linearized following the failed or aborted test. If the flow monitor is re-linearized, a subsequent 3-load (or 3-level) RATA is required, except as otherwise provided in section 2.3.1.3(c)(5) of this appendix.

(g) Data validation for failed RATAs for a CO_2 pollutant concentration monitor (or an O_2 monitor used to measure CO_2 emissions), a NO_X pollutant concentration monitor, and a NO_X-diluent monitoring system shall be done according to paragraphs (g)(1) and (g)(2) of this section:

(1) For a CO_2 pollutant concentration monitor (or an O_2 monitor used to measure CO_2 emissions) which also serves as the diluent component in a NO_X-diluent monitoring system, if the CO_2 (or O_2) RATA is failed, then both the CO_2 (or O_2) monitor and the associated NO_X-diluent system are considered out-of-control, beginning with the hour of completion of the failed CO_2 (or O_2) monitor RATA, and continuing until the hour of completion of subsequent hands-off RATAs which demonstrate that both systems have met the applicable relative accuracy specifications in sections 3.3.2 and 3.3.3 of appendix A to this part, unless the option in paragraph (b)(3) of this section to use the data validation procedures and associated timelines in §75.20(b)(3)(ii) through (b)(3)(ix) has been selected, in which case the beginning and end of the out-of-control period shall be determined in accordance with §75.20(b)(3)(vii)(A) and (B).

(2) This paragraph (g)(2) applies only to a NO_X pollutant concentration monitor that serves both as the NO_X component of a NO_X concentration monitoring system (to measure NO_X mass emissions) and as the NO_X component in a NO_X-diluent monitoring system (to measure NO_X emission rate in lb/mmBtu). If the RATA of the NO_X concentration monitoring system is failed, then both the NO_X concentration monitoring system and the associated NO_X-diluent monitoring system are considered out-of-control, beginning with the hour of completion of the failed NO_X concentration RATA, and continuing until the hour of completion of subsequent hands-off RATAs which demonstrate that both systems have met the applicable relative accuracy specifications in sections 3.3.2 and 3.3.7 of appendix A to this part, unless the option in paragraph (b)(3) of this section to use

the data validation procedures and associated timelines in §75.20(b)(3)(ii) through (b)(3)(ix) has been selected, in which case the beginning and end of the out-of-control period shall be determined in accordance with §75.20(b)(3)(vii)(A) and (B).

(h) For each monitoring system, report the results of all completed and partial RATAs that affect data validation (i.e., all completed, passed RATAs; all completed, failed RATAs; and all RATAs aborted due to a problem with the CEMS, including trial RATA runs counted as failed test attempts under paragraph (b)(2) of this section or under §75.20(b)(3)(vii)(F)) in the quarterly report required under §75.64. Note that RATA attempts that are aborted or invalidated due to problems with the reference method or due to operational problems with the affected unit(s) need not be reported. Such runs do not affect the validation status of emission data recorded by the CEMS. However, a record of all RATAs, trial RATA runs and RATA attempts (whether reported or not) must be kept on-site as part of the official test log for each monitoring system.

(i) Each time that a hands-off RATA of an SO_2 pollutant concentration monitor, a NO_x-diluent monitoring system, a NO_X concentration monitoring system, or a flow monitor is passed, perform a bias test in accordance with section 7.6.4 of appendix A to this part. Apply the appropriate bias adjustment factor to the reported SO_2, NO_X, or flow rate data, in accordance with section 7.6.5 of appendix A to this part.

(j) Failure of the bias test does not result in the monitoring system being out-of-control.

(k) The results of any certification, recertification, diagnostic, or quality assurance test required under this part may not be used to validate the emissions data required under this part, if the test is performed using EPA Protocol gas from a production site that is not participating in the PGVP, except as provided in §75.21(g)(7) or if the cylinder(s) are analyzed by an independent laboratory and shown to meet the requirements of section 5.1.4(b) of appendix A to this part.

2.3.3 RATA Grace Period

(a) The owner or operator has a grace period of 720 consecutive unit operating hours, as defined in §72.2 of this chapter (or, for CEMS installed on common stacks or bypass stacks, 720 consecutive stack operating hours, as defined in §72.2 of this chapter), in which to complete the required RATA for a particular CEMS whenever:

(1) A required RATA has not been performed by the end of the QA operating quarter in which it is due; or

(2) A required 3-load flow RATA has not been performed by the end of the calendar quarter in which it is due; or

(3) For a unit which is conditionally exempted under §75.21(a)(7) from the SO_2 RATA requirements of this part, an SO_2 RATA has not been completed by the end of the calendar quarter in which the annual usage of fuel(s) with a sulfur content higher than very low sulfur fuel (as defined in §72.2 of this chapter) exceeds 480 hours; or

(4) Eight successive calendar quarters have elapsed, following the quarter in which a RATA was last performed, without a subsequent RATA having been done, due either to infrequent operation of the unit(s) or frequent combustion of very low sulfur fuel, as defined in §72.2 of this chapter (SO_2 monitors, only), or a combination of these factors.

(b) Except for SO_2 monitoring system RATAs, the grace period shall begin with the first unit (or stack) operating hour following the calendar quarter in which the required RATA was due. For SO_2 monitor RATAs, the grace period shall begin with the first unit (or stack) operating hour in which fuel with a total sulfur content higher than that of very low sulfur fuel (as defined in §72.2 of this chapter) is burned in the unit(s), following the quarter in which the required RATA is due. Data validation during a RATA grace period shall be done in accordance with the applicable provisions in section 2.3.2 of this appendix.

(c) If, at the end of the 720 unit (or stack) operating hour grace period, the RATA has not been completed, data from the monitoring system shall be invalid, beginning with the first unit operating hour following the expiration of the grace period. Data from the CEMS remain invalid until the hour of completion of a subsequent hands-off RATA. The deadline for the next test shall be either two QA operating quarters (if a semiannual RATA frequency is obtained) or four QA operating quarters (if an annual RATA frequency is obtained) after the quarter in which the RATA is completed, not to exceed eight calendar quarters.

(d) When a RATA is done during a grace period in order to satisfy a RATA requirement from a previous quarter, the deadline for the next RATA shall determined as follows:

(1) If the grace period RATA qualifies for a reduced, (i.e., annual), RATA frequency the deadline for the next RATA shall be set at three QA operating quarters after the quarter in which the grace period test is completed.

(2) If the grace period RATA qualifies for the standard, (i.e., semiannual), RATA frequency the deadline for the next RATA shall be set at two QA operating quarters after the quarter in which the grace period test is completed.

(3) Notwithstanding these requirements, no more than eight successive calendar quarters shall elapse after the quarter in which the grace period test is completed, without a subsequent RATA having been conducted.

2.3.4 Bias Adjustment Factor

Except as otherwise specified in section 7.6.5 of appendix A to this part, if an SO_2 pollutant concentration monitor, a flow monitor, a NO_X-diluent CEMS, or a NO_X concentration monitoring system used to calculate NO_X mass emissions fails the bias test specified in section 7.6 of appendix A to this part, use the bias adjustment factor given in Equations A-11 and A-12 of appendix A to this part or the allowable alternative BAF specified in section 7.6.5(b) of appendix A of this part, to adjust the monitored data.

2.4 Recertification, Quality Assurance, RATA Frequency and Bias Adjustment Factors (Special Considerations)

(a) When a significant change is made to a monitoring system such that recertification of the monitoring system is required in accordance with §75.20(b), a recertification test (or tests) must be performed to ensure that the CEMS continues to generate valid data. In all recertifications, a RATA will be one of the required tests; for some recertifications, other tests will also be required. A recertification test may be used to satisfy the quality assurance test requirement of this appendix. For example, if, for a particular change made to a CEMS, one of the required recertification tests is a linearity check and the linearity check is successful, then, unless another such recertification event occurs in that same QA operating quarter, it would not be necessary to perform an additional linearity test of the CEMS in that quarter to meet the quality assurance requirement of section 2.2.1 of this appendix. For this reason, EPA recommends that owners or operators coordinate component replacements, system upgrades, and other events that may require recertification, to the extent practicable, with the periodic quality assurance testing required by this appendix. When a quality assurance test is done for the dual purpose of recertification and routine quality assurance, the applicable data validation procedures in §75.20(b)(3) shall be followed.

(b) Except as provided in section 2.3.3 of this appendix, whenever a passing RATA of a gas monitor is performed, or a passing 2-load (or 2-level) RATA or a passing 3-load (or 3-level) RATA of a flow monitor is performed (irrespective of whether the RATA is done to satisfy a recertification requirement or to meet the quality assurance requirements of this appendix, or both), the RATA frequency (semi-annual or annual) shall be established based upon the date and time of completion of the RATA and the relative accuracy percentage obtained. For 2-load (or 2-level) and 3-load (or 3-level) flow RATAs, use the highest percentage relative accuracy at any of the loads (or levels) to determine the RATA frequency. The results of a single-load (or single-level) flow RATA may be used to establish the RATA frequency when the single-load (or single-level) flow RATA is specifically required under section 2.3.1.3(b) of this appendix or when the single-load (or single-level) RATA is allowed under section 2.3.1.3(c) of this appendix for a unit that has operated at one load level (or operating level) for ≥85.0 percent of the time since the last annual flow RATA. No other single-load (or single-level) flow RATA may be used to establish an annual RATA frequency; however, a 2-load or 3-load (or a 2-level or 3-level) flow RATA may be performed at any time or in place of any required single-load (or single-level) RATA, in order to establish an annual RATA frequency.

2.5 Other Audits

Affected units may be subject to relative accuracy test audits at any time. If a monitor or continuous emission monitoring system fails the relative accuracy test during the audit, the monitor or continuous emission monitoring system shall be considered to be out-of-control beginning with the date and time of completion of the audit, and continuing until a successful audit test is completed following corrective action. If a monitor or monitoring system fails the bias test during an audit, use the bias adjustment factor given by equations A-11 and A-12 in appendix A to this part to adjust the monitored data. Apply this adjustment factor from the date and time of completion of the audit until the date and time of completion of a relative accuracy test audit that does not show bias.

Figure 1 to Appendix B of Part 75—Quality Assurance Test Requirements

Test	Basic QA test frequency requirements		
	Daily*	Quarterly*	Semiannual or annual*
Calibration Error Test (2 pt.)	X		
Interference Check (flow)	X		
Flow-to-Load Ratio		X	
Leak Check (DP flow monitors)		X	
Linearity Check*(3 pt.)		X	
RATA (SO_2, NO_X, CO_2, O_2, H_2O)[1]			X
RATA (flow)[12]			X

*"Daily" means operating days, only. "Quarterly" means once every QA operating quarter. "Semiannual" means once every two QA operating quarters. "Annual" means once every four QA operating quarters.

[1]Conduct RATA annually (i.e., once every four QA operating quarters) rather than semiannually, if monitor meets accuracy requirements to qualify for less frequent testing.

[2]For flow monitors installed on peaking units, bypass stacks, or units that qualify for single-level RATA testing under section 6.5.2(e) of this part, conduct all RATAs at a single, normal load (or operating level). For other flow monitors, conduct annual RATAs at two load levels (or operating levels). Alternating single-load and 2-load (or single-level and 2-level) RATAs may be done if a monitor is on a semiannual frequency. A single-load (or single-level) RATA may be done in lieu of a 2-load (or 2-level) RATA if, since the last annual flow RATA, the unit has operated at one load level (or operating level) for ≥85.0 percent of the time. A 3-level RATA is required at least once every five years (20 calendar quarters) and whenever a flow monitor is re-characterized, except for flow monitors exempted from 3-level RATA testing under section 6.5.2(b) or 6.5.2(e) of appendix A to this part.

Figure 2 to Appendix B of Part 75—Relative Accuracy Test Frequency Incentive System

RATA	**Semiannual[W]**	**Annual[W]**
SO_2 or NO_X[Y]	7.5% <RA ≤10.0% or ±15.0 ppm[X]	RA ≤7.5% or ±12.0 ppm[X].
NO_X-diluent	7.5% <RA ≤10.0% or ±0.020 lb/mmBtu[X]	RA ≤7.5% or ±0. 015 lb/mmBtu[X].
Flow	7.5% <RA ≤10.0% or ±2.0 fps[X]	RA ≤7.5% or ±1.5 fps[X].
CO_2 or O_2	7.5% <RA ≤10.0% or ±1.0% CO_2/O_2[X]	RA ≤7.5% or ±0.7% CO_2/O_2[X].
Moisture	7.5% <RA ≤10.0% or ±1.5% H_2O[X]	RA ≤7.5% or ±1.0% H_2O[X].

[W]The deadline for the next RATA is the end of the second (if semiannual) or fourth (if annual) successive QA operating quarter following the quarter in which the CEMS was last tested. Exclude calendar quarters with fewer than 168 unit operating hours (or, for common stacks and bypass stacks, exclude quarters with fewer than 168 stack operating hours) in determining the RATA deadline. For SO_2 monitors, QA operating quarters in which only very low sulfur fuel as defined in §72.2 of this chapter, is combusted may also be excluded. However, the exclusion of calendar quarters is limited as follows: the deadline for the next RATA shall be no more than 8 calendar quarters after the quarter in which a RATA was last performed. A 720 operating hour grace period is available if the RATA cannot be completed by the deadline.

[X]The difference between monitor and reference method mean values applies to moisture monitors, CO_2, and O_2 monitors, low emitters of SO_2, NO_X, and low flow, only.

[Y]A NO_X concentration monitoring system used to determine NO_X mass emissions under §75.71.

FIGURE 3 TO APPENDIX B OF PART 75--SINGLE COMPONENT PLUS BALANCE GAS CYLINDERS
EPA PROTOCOL GAS VERIFICATION PROGRAM RESULTS
EPA CYLINDER GAS ASSAYS PERFORMED BY NIST [NIST to Insert: Month, Year]

Specialty Gas Company Name	EPA Protocol Gas Production Site Name	Vendor ID	Stamped Cylinder ID	Gas Component, e.g., SO2							Supplied Complete Documentation (Yes/No)
				Tag Value (e.g., ppm SO2)	Audit Results				Vendor Analytical Method (e.g., FTIR)	Vendor Ref Std Used (e.g., NTRM)	
					Orig Tag Value (Pass/Fail)	Orig Tag (% dif)	Re-analyzed Value (Pass/Fail)	Re-analysis (% dif)			

% dif = 100 x (Tag Value – NIST Value) / NIST Value

A gaseous component is said to fail when the absolute value of the difference between the audit and vendor concentration values is greater than 2.20%. The 2.20% value is determined by using the "paired t test" at 95% confidence, with an uncertainty of plus or minus 2.0% (fixed by Part 75, Appendix A, section 5.1.4(b)) for the gas vendor and an expanded uncertainty (coverage factor k=2) of plus or minus 1.0% (maximum acceptable) for the audit. If on future audits, e.g., for very low concentration gases, the plus or minus 1.0% audit expanded uncertainty value changes, the 2.20% value may change. If the difference between the audit value and the vendor value is plus or minus 2.20% or less, then (because of the uncertainties in the total measurement system) statistically there is no difference between the two values. Thus, a difference of 2.10% would be interpreted as being equal to one of, for example, 0.40%.

Nothing can be said regarding the performance of any EPA Protocol gas production site inadvertently not included in the audit. Any accuracy assessment is an instantaneous snapshot of the process being measured. These results should not be regarded as a final statement on the accuracy of EPA Protocol gases. They can be used as a general indicator of the current status of the accuracy of EPA Protocol gases as a whole. However, individual results should not be taken as definitive indicators of the analytical capabilities of individual producers. EPA presents this information without assigning a rating to the gas vendors, for example, who is the best, who is approved, or is not approved and specifically does not endorse any particular vendor.

NOTE: For cylinders with more than one component plus balance gas, change the title appropriately, e.g., "FIGURE 3 TO APPENDIX B OF PART 75 – BI-BLEND PLUS BALANCE GAS CYLINDERS . . ." and add appropriate columns to Figure 3 for the additional components following the same format used in the columns for SO2 above.

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[58 FR 3701, Jan. 11, 1993, as amended at 60 FR 26546, 26571, May 17, 1995; 61 FR 59165, Nov. 20, 1996; 64 FR 28644, May 26, 1999; 64 FR 37582, July 12, 1999; 67 FR 40456, 40457, June 12, 2002; 67 FR 53505, Aug. 16, 2002; 67 FR 57274, Sept. 9, 2002; 70 FR 28693, May 18, 2005; 72 FR 51528, Sept. 7, 2007; 73 FR 4367, Jan. 24, 2008; 76 FR 17321, Mar. 28, 2011]

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Appendix C to Part 75—Missing Data Estimation Procedures

1. Parametric Monitoring Procedure for Missing SO_2 Concentration or NO_X Emission Rate Data

1.1 Applicability

The owner or operator of any affected unit equipped with post-combustion SO_2 or NO_X emission controls and SO_2 pollutant concentration monitors and/or NO_X continuous emission monitoring systems at the inlet and outlet of the emission control system may apply to the Administrator for approval and certification of a parametric, empirical, or process simulation method or model for calculating substitute data for missing data periods. Such methods may be used to parametrically estimate the removal efficiency of the SO_2 of postcombustion NO_X emission controls which, with the monitored inlet concentration or emission rate data, may be used to estimate the average concentration of SO_2 emissions or average emission rate of NO_X discharged to the atmosphere. After approval by the Administrator, such method or model may be used for filling in missing SO_2 concentration or NO_X emission rate data when data from the outlet SO_2 pollutant concentration monitor or outlet NO_X continuous emission monitoring system have been reported with an annual monitor data availability of 90.0 percent or more.

Base the empirical and process simulation methods or models on the fundamental chemistry and engineering principles involved in the treatment of pollutant gas. On a case-by-case basis, the Administrator may pre-certify commercially available process simulation methods and models.

1.2 Petition Requirements

Continuously monitor, determine, and record hourly averages of the estimated SO_2 or NO_X removal efficiency and of the parameters specified below, at a minimum. The affected facility shall supply additional parametric information where appropriate. Measure the SO_2 concentration or NO_X emission rate, removal efficiency of the add-on emission controls, and the parameters for at least 2160 unit operating hours. Provide information for all expected operating conditions and removal efficiencies. At least 4 evenly spaced data points are required for a valid hourly average, except during periods of calibration, maintenance, or quality assurance activities, during which 2 data points per hour are sufficient. The Administrator will review all applications on a case-by-case basis.

1.2.1 Parameters for Wet Flue Gas Desulfurization System

1.2.1.1 Number of scrubber modules in operation.

1.2.1.2 Total slurry rate to each scrubber module (gal per min).

1.2.1.3 In-line absorber pH of each scrubber module.

1.2.1.4 Pressure differential across each scrubber module (inches of water column).

1.2.1.5 Unit load (MWe).

1.2.1.6 Inlet and outlet SO_2 concentration as determined by the monitor or missing data substitution procedures.

1.2.1.7 Percent solids in slurry for each scrubber module.

1.2.1.8 Any other parameters necessary to verify scrubber removal efficiency, if the Administrator determines the parameters above are not sufficient.

1.2.2 Parameters for Dry Flue Gas Desulfurization System

1.2.2.1 Number of scrubber modules in operation.

1.2.2.2 Atomizer slurry flow rate to each scrubber module (gal per min).

1.2.2.3 Inlet and outlet temperature for each scrubber module (°F).

1.2.2.4 Pressure differential across each scrubber module (inches of water column).

1.2.2.5 Unit load (MWe).

1.2.2.6 Inlet and outlet SO_2 concentration as determined by the monitor or missing data substitution procedures.

1.2.2.7 Any other parameters necessary to verify scrubber removal efficiency, if the Administrator determines the parameters above are not sufficient.

1.2.3 Parameters for Other Flue Gas Desulfurization Systems

If SO_2 control technologies other than wet or dry lime or limestone scrubbing are selected for flue gas desulfurization, a corresponding empirical correlation or process simulation parametric method using appropriate parameters may be developed by the owner or operator of the affected unit, and then reviewed and approved or modified by the Administrator on a case-by-case basis.

1.2.4 Parameters for Post-Combustion NO_X Emission Controls

1.2.4.1 Inlet air flow rate to the unit (boiler) (mcf/hr).

1.2.4.2 Excess oxygen concentration of flue gas at stack outlet (percent).

1.2.4.3 Carbon monoxide concentration of flue gas at stack outlet (ppm).

1.2.4.4 Temperature of flue gas at outlet of the unit (°F).

1.2.4.5 Inlet and outlet NO_X emission rate as determined by the NO_X continuous emission monitoring system or missing data substitution procedures.

1.2.4.6 Any other parameters specific to the emission reduction process necessary to verify the NO_X control removal efficiency, (e.g., reagent feedrate in gal/mi).

1.3 Correlation of Emissions With Parameters

Establish a method for correlating hourly averages of the parameters identified above with the percent removal efficiency of the SO_2 or post-combustion NO_X emission controls under varying unit operating loads. Equations 1-7 in §75.15 may be used to estimate the percent removal efficiency of the SO_2 emission controls on an hourly basis.

Each parametric data substitution procedure should develop a data correlation procedure to verify the performance of the SO_2 emission controls or post-combustion NO_X emission controls, along with the SO_2 pollutant concentration monitor and NO_X continuous emission monitoring system values for varying unit load ranges.

For NO_X emission rate data, and wherever the performance of the emission controls varies with the load, use the load range procedure provided in section 2.2 of this appendix.

1.4 Calculations

1.4.1 Use the following equation to calculate substitute data for filling in missing (outlet) SO_2 pollutant concentration monitor data.

$$M_o = I_c (1-E)$$

(Eq. C-1)

where,

M_o = Substitute data for outlet SO_2 concentration, ppm.

I_c = Recorded inlet SO_2 concentration, ppm.

E = Removal efficiency of SO_2 emission controls as determined by the correlation procedure described in section 1.3 of this appendix.

1.4.2 Use the following equation to calculate substitute data for filling in missing (outlet) NO_X emission rate data.

$$M_o = I_c (1-E)$$

(Eq. C-2)

where,

M_o = Substitute data for outlet NO_X emission rate, lb/mmBtu.

I_c = Recorded inlet NO_X emission rate, lb/mmBtu.

E = Removal efficiency of post-combustion NO_X emission controls determined by the correlation procedure described in section 1.3 of this appendix.

1.5 Missing Data

1.5.1 If both the inlet and the outlet SO_2 pollutant concentration monitors are unavailable simultaneously, use the maximum inlet SO_2 concentration recorded by the inlet SO_2 pollutant concentration monitor during the previous 720 quality-assured monitor operating hours to substitute for the inlet SO_2 concentration in equation C-1 of this appendix.

1.5.2 If both the inlet and outlet NO_X continuous emission monitoring systems are unavailable simultaneously, use the maximum inlet NO_X emission rate for the corresponding unit load recorded by the NO_X continuous emission monitoring system at the inlet during the previous 2160 quality-assured monitor operating hours to substitute for the inlet NO_X emission rate in equation C-2 of this appendix.

1.6 Application

Apply to the Administrator for approval and certification of the parametric substitution procedure for filling in missing SO_2 concentration or NO_X emission rate data using the established criteria and information identified above. DO not use this procedure until approved by the Administrator.

2. Load-based Procedure for Missing Flow Rate, NO_X Concentration, and NO_X Emission Rate Data

2.1 Applicability

This procedure is applicable for data from all affected units for use in accordance with the provisions of this part to provide substitute data for volumetric flow rate (scfh), NO_X emission rate (in lb/mmBtu) from NO_X-diluent continuous emission monitoring systems, and NO_X concentration data (in ppm) from NOx concentration monitoring systems used to determine NO_X mass emissions.

2.2 Procedure

2.2.1 For a single unit, establish ten operating load ranges defined in terms of percent of the maximum hourly average gross load of the unit, in gross megawatts (MWge), as shown in Table C-1. (Do not use integrated hourly gross load in MW-hr.) For units sharing a common stack monitored with a single flow monitor, the load ranges for flow (but not for NO_X) may be broken down into 20 operating load ranges in increments of 5.0 percent of the combined maximum hourly average gross load of all units utilizing the common stack. If this option is selected, the twentieth (uppermost) operating load range shall include all values greater than 95.0 percent of the maximum hourly average gross load. For a cogenerating unit or other unit at which some portion of the heat input is not used to produce electricity or for a unit for which hourly average gross load in MWge is not recorded separately, use the hourly gross steam load of the unit, in pounds of steam per hour at the measured temperature (°F) and pressure (psia) instead of MWge. Indicate a change in the number of load ranges or the units of loads to be used in the precertification section of the monitoring plan.

Table C-1—Definition of Operating Load Ranges for Load-based Substitution Data Procedures

Operating load range	Percent of maximum hourly gross load or maximum hourly gross steam load (percent)
1	0-10
2	>10-20
3	>20-30
4	>30-40
5	>40-50
6	>50-60
7	>60-70
8	>70-80
9	>80-90
10	>90

2.2.2 Beginning with the first hour of unit operation after installation and certification of the flow monitor or the NO_X-diluent continuous emission monitoring system (or a NO_X concentration monitoring system used to determine NO_X mass emissions, as defined in §75.71(a)(2)), for each hour of unit operation record a number, 1 through 10, (or 1 through 20 for flow at common stacks) that identifies the operating load range corresponding to the integrated hourly gross load of the unit(s) recorded for each unit operating hour.

2.2.3 Beginning with the first hour of unit operation after installation and certification of the flow monitor or the NO_X-diluent continuous emission monitoring system (or a NO_X concentration monitoring system used to determine NO_X mass emissions, as defined in §75.71(a)(2)) and continuing thereafter, the data acquisition and handling system must be capable of calculating and recording the following information for each unit operating hour of missing flow or NO_X data within each identified load range during the shorter of: (a) the previous 2,160 quality-assured monitor operating hours (on a rolling basis), or (b) all previous quality-assured monitor operating hours.

2.2.3.1 Average of the hourly flow rates reported by a flow monitor, in scfh.

2.2.3.2 The 90th percentile value of hourly flow rates, in scfh.

2.2.3.3 The 95th percentile value of hourly flow rates, in scfh.

2.2.3.4 The maximum value of hourly flow rates, in scfh.

2.2.3.5 Average of the hourly NO_X emission rate, in lb/mmBtu, reported by a NO_X continuous emission monitoring system.

2.2.3.6 The 90th percentile value of hourly NO_X emission rates, in lb/mmBtu.

2.2.3.7 The 95th percentile value of hourly NO_X emission rates, in lb/mmBtu.

2.2.3.8 The maximum value of hourly NO_X emission rates, in lb/mmBtu.

2.2.3.9 Average of the hourly NO_X pollutant concentrations, in ppm, reported by a NO_X concentration monitoring system used to determine NO_X mass emissions, as defined in §75.71(a)(2).

2.2.3.10 The 90th percentile value of hourly NO_X pollutant concentration, in ppm.

2.2.3.11 The 95th percentile value of hourly NO_X pollutant concentration, in ppm.

2.2.3.12 The maximum value of hourly NO_X pollutant concentration, in ppm.

2.2.4 Calculate all monitor or continuous emission monitoring system data averages, maximum values, and percentile values determined by this procedure using bias adjusted values in the load ranges.

2.2.5 When a bias adjustment is necessary for the flow monitor and/or the NO_X-diluent continuous emission monitoring system (and/or the NO_X concentration monitoring system used to determine NO_X mass emissions, as defined in §75.71(a)(2)), apply the adjustment factor to all monitor or continuous emission monitoring system data values placed in the load ranges.

2.2.6 Use the calculated monitor or monitoring system data averages, maximum values, and percentile values to substitute for missing flow rate and NO_X emission rate data (and where applicable, NO_X concentration data) according to the procedures in subpart D of this part.

3. Non-load-based Procedure for Missing Flow Rate, NO_X Concentration, and NO_X Emission Rate Data (Optional)

3.1 Applicability

For affected units that do not produce electrical output in megawatts or thermal output in klb/hr of steam, this procedure may be used in accordance with the provisions of this part to provide substitute data for volumetric flow rate (scfh), NO_X emission rate (in lb/mmBtu) from NO_X-diluent continuous emission monitoring systems, and NO_X concentration data (in ppm) from NO_X concentration monitoring systems used to determine NO_X mass emissions.

3.2 Procedure

3.2.1 For each monitored parameter (flow rate, NO_X emission rate, or NO_X concentration), establish at least two, but no more than ten operational bins, corresponding to various operating conditions and parameters (or combinations of these) that affect volumetric flow rate or NO_X emissions. Include a complete description of each operational bin in the hardcopy portion of the monitoring plan required under §75.53(e)(2), identifying the unique combination of parameters and operating conditions associated with the bin and explaining the relationship between these parameters and conditions and the magnitude of the stack gas flow rate or NO_X emissions. Assign a unique number, 1 through 10, to each operational bin. Examples of conditions and parameters that may be used to define operational bins include unit heat input, type of fuel combusted, specific stages of an industrial process, or (for common stacks), the particular combination of units that are in operation.

3.2.2 In the electronic quarterly report required under §75.64, indicate for each hour of unit operation the operational bin associated with the NO_X or flow rate data, by recording the number assigned to the bin under section 3.2.1 of this appendix.

3.2.3 The data acquisition and handling system must be capable of properly identifying and recording the operational bin number for each unit operating hour. The DAHS must also be capable of calculating and recording the following information (as applicable) for each unit operating hour of missing flow or NO_X data within each identified operational bin during the shorter of:

(a) The previous 2,160 quality-assured monitor operating hours (on a rolling basis), or

(b) All previous quality-assured monitor operating hours in the previous 3 years:

3.2.3.1 Average of the hourly flow rates reported by a flow monitor (scfh).

3.2.3.2 The 90th percentile value of hourly flow rates (scfh).

3.2.3.3 The 95th percentile value of hourly flow rates (scfh).

3.2.3.4 The maximum value of hourly flow rates (scfh).

3.2.3.5 Average of the hourly NO_X emission rates, in lb/mmBtu, reported by a NO_X-diluent continuous emission monitoring system.

3.2.3.6 The 90th percentile value of hourly NO_X emission rates (lb/mmBtu).

3.2.3.7 The 95th percentile value of hourly NO_X emission rates (lb/mmBtu).

3.2.3.8 The maximum value of hourly NO_X emission rates, in (lb/mmBtu).

3.2.3.9 Average of the hourly NO_X pollutant concentrations (ppm), reported by a NO_X concentration monitoring system used to determine NO_X mass emissions, as defined in §75.71(a)(2).

3.2.3.10 The 90th percentile value of hourly NO_X pollutant concentration (ppm).

3.2.3.11 The 95th percentile value of hourly NO_X pollutant concentration (ppm).

3.2.3.12 The maximum value of hourly NO_X pollutant concentration (ppm).

3.2.4 When a bias adjustment is necessary for the flow monitor and/or the NO_X-diluent continuous emission monitoring system (and/or the NO_X concentration monitoring system), apply the bias adjustment factor to all data values placed in the operational bins.

3.2.5 Calculate all CEMS data averages, maximum values, and percentile values determined by this procedure using bias-adjusted values.

3.2.6 Use the calculated monitor or monitoring system data averages, maximum values, and percentile values to substitute for missing flow rate and NO_X emission rate data (and where applicable, NO_X concentration data) according to the procedures in subpart D of this part.

[58 FR 3701, Jan. 11, 1993, as amended at 60 FR 26547, 26548, May 17, 1995; 63 FR 57313, Oct. 27, 1998; 64 FR 28652, May 26, 1999; 67 FR 40459, June 12, 2002]

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Appendix D to Part 75—Optional SO_2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units

1. Applicability

1.1 This protocol may be used in lieu of continuous SO_2 pollutant concentration and flow monitors for the purpose of determining hourly SO_2 mass emissions and heat input from: gas-fired units, as defined in §72.2 of this chapter, or oil-fired units, as defined in §72.2 of this chapter. Section 2.1 of this appendix provides procedures for measuring oil or gaseous fuel flow using a fuel flowmeter, section 2.2 of this appendix provides procedures for conducting oil sampling and analysis to determine sulfur content and gross calorific value (GCV) of fuel oil, and section 2.3 of this appendix provides procedures for determining the sulfur content and GCV of gaseous fuels.

1.2 Pursuant to the procedures in §75.20, complete all testing requirements to certify use of this protocol in lieu of a flow monitor and an SO_2 continuous emission monitoring system. Complete all testing requirements no later than the applicable deadline specified in §75.4. Apply to the Administrator for initial certification to use this protocol no later than 45 days after the completion of all certification tests.

2. Procedure

2.1 Fuel Flowmeter Measurements

For each hour when the unit is combusting fuel, measure and record the flow rate of fuel combusted by the unit, except as provided in section 2.1.4 of this appendix. Measure the flow rate of fuel with an in-line fuel flowmeter, and automatically record the data with a data acquisition and handling system, except as provided in section 2.1.4 of this appendix.

2.1.1 Measure the flow rate of each fuel entering and being combusted by the unit. If, on an annual basis, more than 5.0 percent of the fuel from the main pipe is diverted from the unit without being burned and that diversion occurs downstream of the fuel flowmeter, an additional in-line fuel flowmeter is required to account for the unburned fuel. In this case, record the flow rate of each fuel combusted by the unit as the difference between the flow measured in the pipe leading to the unit and the flow in the pipe diverting fuel away from the unit. However, the additional fuel flowmeter is not required if, on an annual basis, the total amount of fuel diverted away from the unit, expressed as a percentage of the total annual fuel usage by the unit is demonstrated to be less than or equal to 5.0 percent. The owner or operator may make this demonstration in the following manner:

2.1.1.1 For existing units with fuel usage data from fuel flowmeters, if data are submitted from a previous year demonstrating that the total diverted yearly fuel does not exceed 5% of the total fuel used; or

2.1.1.2 For new units which do not have historical data, if a letter is submitted signed by the designated representative certifying that, in the future, the diverted fuel will not exceed 5.0% of the total annual fuel usage; or

2.1.1.3 By using a method approved by the Administrator under §75.66(d).

2.1.2 Install and use fuel flowmeters meeting the requirements of this appendix in a pipe going to each unit, or install and use a fuel flowmeter in a common pipe header (as defined in §72.2). However, the use of a fuel flowmeter in a common pipe header and the provisions of sections 2.1.2.1 and 2.1.2.2 of this appendix shall not apply to any unit that is using the provisions of subpart H of this part to monitor, record, and report NO_X mass emissions under a State or federal NO_X mass emission reduction program, unless both of the following are true: all of the units served by the common pipe are affected units, and all of the units have similar efficiencies. When a fuel flowmeter is installed in a common pipe header, proceed as follows:

2.1.2.1 Measure the fuel flow rate in the common pipe, and combine SO_2 mass emissions (Acid Rain Program units only) for the affected units for recordkeeping and compliance purposes; and

2.1.2.2 Apportion the heat input rate measured at the common pipe to the individual units, using Equation F-21a, F-21b, or F-21d in appendix F to this part.

2.1.3 For a gas-fired unit or an oil-fired unit that continuously or frequently combusts a supplemental fuel for flame stabilization or safety purposes, measure the flow rate of the supplemental fuel with a fuel flowmeter meeting the requirements of this appendix.

2.1.4 Situations in Which Certified Flowmeter is Not Required

2.1.4.1 Start-up or Ignition Fuel

For an oil-fired unit that uses gas solely for start-up or burner ignition, a gas-fired unit that uses oil solely for start-up or burner ignition, or an oil-fired unit that uses a different grade of oil solely for start-up or burner ignition, a fuel flowmeter for the start-up fuel is permitted but not required. Estimate the volume of oil combusted for each start-up or ignition either by using a fuel flowmeter or by using the dimensions of the storage container and measuring the depth of the fuel in the storage container before and after each start-up or ignition. A fuel flowmeter used solely for start-up or ignition fuel is not subject to the calibration requirements of sections 2.1.5 and 2.1.6 of this appendix. Gas combusted solely for start-up or burner ignition does not need to be measured separately.

2.1.4.2 Gas or Oil Flowmeter Used for Commercial Billing

A gas or oil flowmeter used for commercial billing of natural gas or oil may be used to measure, record, and report hourly fuel flow rate. A gas or oil flowmeter used for commercial billing of natural gas or oil is not required to meet the certification requirements of section 2.1.5 of this appendix or the quality assurance requirements of section 2.1.6 of this appendix under the following circumstances:

(a) The gas or oil flowmeter is used for commercial billing under a contract, provided that the company providing the gas or oil under the contract and each unit combusting the gas or oil do not have any common owners and are not owned by subsidiaries or affiliates of the same company;

(b) The designated representative reports hourly records of gas or oil flow rate, heat input rate, and emissions due to combustion of natural gas or oil;

(c) The designated representative also reports hourly records of heat input rate for each unit, if the gas or oil flowmeter is on a common pipe header, consistent with section 2.1.2 of this appendix;

(d) The designated representative reports hourly records directly from the gas or oil flowmeter used for commercial billing if these records are the values used, without adjustment, for commercial billing, or reports hourly records using the missing data procedures of section 2.4 of this appendix if these records are not the values used, without adjustment, for commercial billing; and

(e) The designated representative identifies the gas or oil flowmeter in the unit's monitoring plan.

2.1.4.3 Emergency Fuel

The designated representative of a unit that is restricted by its Federal, State or local permit to combusting a particular fuel only during emergencies where the primary fuel is not available is exempt from certifying a fuel flowmeter for use during combustion of the emergency fuel. During any hour in which the emergency fuel is combusted, report the hourly heat input to be the maximum rated heat input of the unit for the fuel. Use the maximum potential sulfur content for the fuel (from Table D-6 of this appendix) and the fuel flow rate corresponding to the maximum hourly heat input to calculate the hourly SO_2 mass emission rate, using Equations D-2 through D-4 (as applicable). Alternatively, if a certified fuel flowmeter is available for the emergency fuel, you may use the measured hourly fuel flow rates in the calculations. Also, if daily samples or weekly composite samples (fuel oil, only) of the fuel's total sulfur content, GCV, and (if applicable) density are taken during the combustion of the emergency fuel, as described in section 2.2 or 2.3 of this appendix, the sample results may be used to calculate the hourly SO_2 emissions and heat input rates, in lieu of using maximum potential values. The designated representative shall also provide notice under §75.61(a)(6) for each period when the emergency fuel is combusted.

2.1.5 Initial Certification Requirement for all Fuel Flowmeters

For the purposes of initial certification, each fuel flowmeter used to meet the requirements of this protocol shall meet a flowmeter accuracy of 2.0 percent of the upper range value (i.e. maximum fuel flow rate measurable by the flowmeter) across the range of fuel flow rate to be measured at the unit. Flowmeter accuracy may be determined under section 2.1.5.1 of this appendix for initial certification in any of the following ways (as applicable): by design (orifice, nozzle, and venturi-type flowmeters, only) or by measurement under laboratory conditions; by the manufacturer; by an independent laboratory; or by the owner or operator. Flowmeter accuracy may also be determined under section 2.1.5.2 of this appendix by in-line comparison against a reference flowmeter.

2.1.5.1 Use the procedures in the following standards to verify flowmeter accuracy or design, as appropriate to the type of flowmeter: ASME MFC-3M-2004, Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi; ASME MFC-4M-1986 (Reaffirmed 1997), Measurement of Gas Flow by Turbine Meters; American Gas Association Report No. 3, Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids Part 1: General Equations and Uncertainty Guidelines (October 1990 Edition), Part 2: Specification and Installation Requirements (February 1991 Edition), and Part 3: Natural Gas Applications (August 1992 edition) (excluding the modified flow-calculation method in part 3); Section 8, Calibration from American Gas Association Transmission Measurement Committee Report No. 7: Measurement of Gas by Turbine Meters (Second Revision, April 1996); ASME-MFC-5M-1985 (Reaffirmed 1994), Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters; ASME MFC-6M-1998, Measurement of Fluid Flow in Pipes Using Vortex Flowmeters; ASME MFC-7M-1987 (Reaffirmed 1992), Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles; ISO 8316: 1987(E) Measurement of Liquid Flow in Closed Conduits—Method by Collection of the Liquid in a Volumetric Tank; American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 4—Proving Systems, Section 2—Pipe Provers (Provers Accumulating at Least 10,000 Pulses), Second Edition, March 2001, Section 3—Small Volume Provers, First Edition, July 1988, Reaffirmed October 1993, and Section 5—Master-Meter Provers, Second Edition, May 2000; American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 22—Testing Protocol, Section 2—Differential Pressure Flow Measurement Devices, First Edition, August 2005; or ASME MFC-9M-1988 (Reaffirmed 2001), Measurement of Liquid Flow in Closed Conduits by Weighing Method, for all other flowmeter types (all incorporated by reference under §75.6 of this part). The Administrator may also approve other procedures that use equipment traceable to National Institute of Standards and Technology standards. Document such procedures, the equipment used, and the accuracy of the procedures in the monitoring plan for the unit, and submit a petition signed by the designated representative under §75.66(c). If the flowmeter accuracy exceeds 2.0 percent of the upper range value, the flowmeter does not qualify for use under this part.

2.1.5.2 (a) Alternatively, determine the flowmeter accuracy of a fuel flowmeter used for the purposes of this part by comparing it to the measured flow from a reference flowmeter which has been either designed according to the specifications of American Gas Association Report No. 3 or ASME MFC-3M-1989, as cited in section 2.1.5.1 of this appendix, or tested for accuracy during the previous 365 days, using a standard listed in section 2.1.5.1 of this appendix or other procedure approved by the Administrator under §75.66 (all standards incorporated by reference under §75.6). Any secondary elements, such as pressure and temperature transmitters, must be calibrated immediately prior to the comparison. Perform the comparison over a period of no more than seven consecutive unit operating days. Compare the average of three fuel flow rate readings over 20 minutes or longer for each meter at each of three different flow rate levels. The three flow rate levels shall correspond to:

(1) Normal full unit operating load,

(2) Normal minimum unit operating load,

(3) A load point approximately equally spaced between the full and minimum unit operating loads, and

(b) Calculate the flowmeter accuracy at each of the three flow levels using the following equation:

$$ACC = \frac{|R - A|}{URV} \times 100 \qquad (Eq.\ D\text{-}1)$$

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Where:

ACC = Flowmeter accuracy at a particular load level, as a percentage of the upper range value.

R = Average of the three flow measurements of the reference flowmeter.

A = Average of the three measurements of the flowmeter being tested.

URV = Upper range value of fuel flowmeter being tested (i.e. maximum measurable flow).

(c) Notwithstanding the requirement for calibration of the reference flowmeter within 365 days prior to an accuracy test, when an in-place reference meter or prover is used for quality assurance under section 2.1.6 of this appendix, the reference meter calibration requirement may be waived if, during the previous in-place accuracy test with that reference meter, the reference flowmeter and the flowmeter being tested agreed to within ±1.0 percent of each other at all levels tested. This exception to calibration and flowmeter accuracy testing requirements for the reference flowmeter shall apply for periods of no longer than five consecutive years (i.e., 20 consecutive calendar quarters).

2.1.5.3 If the flowmeter accuracy exceeds the specification in section 2.1.5 of this appendix, the flowmeter does not qualify for use for this appendix. Either recalibrate the flowmeter until the flowmeter accuracy is within the performance specification, or replace the flowmeter with another one that is demonstrated to meet the performance specification. Substitute for fuel flow rate using the missing data procedures in section 2.4.2 of this appendix until quality-assured fuel flow data become available.

2.1.5.4 For purposes of initial certification, when a flowmeter is tested against a reference fuel flow rate (i.e., fuel flow rate from another fuel flowmeter under section 2.1.5.2 of this appendix or flow rate from a procedure performed according to a standard incorporated by reference under section 2.1.5.1 of this appendix), report the results of flowmeter accuracy tests in a manner consistent with Table D-1.

Table D-1—Table of Flowmeter Accuracy Results

Test number:____ Test completion date[1]:__________ Test completion time[1]:______					
Reinstallation date[2] (for testing under 2.1.5.1 only):__________ Reinstallation time[2]:______					
Unit or pipe ID: Component/System ID:					
Flowmeter serial number: Upper range value:					
Units of measure for flowmeter and reference flow readings:					
Measurement level (percent of URV)	**Run No.**	**Time of run (HHMM)**	**Candidate flowmeter reading**	**Reference flow reading**	**Percent accuracy (percent of URV)**
Low (Minimum) level	1				
__ percent[3] of URV	2				
	3				
	Average				
Mid-level	1				
__ percent[3] of URV	2				
	3				

	Average				
High (Maximum) level	1				
__ percent[3] of URV	2				
	3				
	Average				

[1]Report the date, hour, and minute that all test runs were completed.

[2]For laboratory tests not performed inline, report the date and hour that the fuel flowmeter was reinstalled following the test.

[3]It is required to test at least at three different levels: (1) normal full unit operating load, (2) normal minimum unit operating load, and (3) a load point approximately equally spaced between the full and minimum unit operating loads.

2.1.6 Quality Assurance

(a) Test the accuracy of each fuel flowmeter prior to use under this part and at least once every four fuel flowmeter QA operating quarters, as defined in §72.2 of this chapter, thereafter. Notwithstanding these requirements, no more than 20 successive calendar quarters shall elapse after the quarter in which a fuel flowmeter was last tested for accuracy without a subsequent flowmeter accuracy test having been conducted. Test the flowmeter accuracy more frequently if required by manufacturer specifications.

(b) Except for orifice-, nozzle-, and venturi-type flowmeters, perform the required flowmeter accuracy testing using the procedures in either section 2.1.5.1 or section 2.1.5.2 of this appendix. Each fuel flowmeter must meet the accuracy specification in section 2.1.5 of this appendix.

(c) For orifice-, nozzle-, and venturi-type flowmeters, either perform the required flowmeter accuracy testing using the procedures in section 2.1.5.2 of this appendix or perform a transmitter accuracy test for the initial certification and once every four fuel flowmeter QA operating quarters thereafter. Perform a primary element visual inspection for the initial certification and once every 12 calendar quarters thereafter, according to the procedures in sections 2.1.6.1 through 2.1.6.4 of this appendix for periodic quality assurance.

(d) Notwithstanding the requirements of this section, if the procedures of section 2.1.7 (fuel flow-to-load test) of this appendix are performed during each fuel flowmeter QA operating quarter, subsequent to a required flowmeter accuracy test or (if applicable) transmitter accuracy test and primary element inspection, those procedures may be used to meet the requirement for periodic quality assurance testing for a period of up to 20 calendar quarters from the previous accuracy test or (if applicable) transmitter accuracy test and primary element inspection.

(e) When accuracy testing of the orifice, nozzle, or venturi meter is performed according to section 2.1.5.2 of this appendix, record the information displayed in Table D-1 in this section. At a minimum, record the overall accuracy results for the fuel flowmeter at the three flow rate levels specified in section 2.1.5.2 of this appendix.

(f) Report the results of all fuel flowmeter accuracy tests, transmitter or transducer accuracy tests, and primary element inspections, as applicable, in the emissions report for the quarter in which the quality assurance tests are performed, using the electronic format specified by the Administrator under §75.64.

2.1.6.1 Transmitter or Transducer Accuracy Test for Orifice-, Nozzle-, and Venturi-Type Flowmeters

(a) Calibrate the differential pressure transmitter or transducer, static pressure transmitter or transducer, and temperature transmitter or transducer, as applicable, using equipment that has a current certificate of traceability to NIST standards. Check the calibration of each transmitter or transducer by comparing its readings to that of the NIST traceable equipment at least once at each of the following levels: the zero-level and at least two other upscale levels (e.g., “mid” and “high”), such that the full range of transmitter or transducer readings corresponding to normal unit operation is represented. For temperature transmitters, the zero and upscale levels may correspond to fixed reference points, such as the freezing point or boiling point of water.

(b) Calculate the accuracy of each transmitter or transducer at each level tested, using the following equation:

$$ACC = \frac{|R - T|}{FS} \times 100 \qquad (Eq.\ D\text{-}1a)$$

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Where:

ACC = Accuracy of the transmitter or transducer as a percentage of full-scale.

R = Reading of the NIST traceable reference value (in milliamperes, inches of water, psi, or degrees).

T = Reading of the transmitter or transducer being tested (in milliamperes, inches of water, psi, or degrees, consistent with the units of measure of the NIST traceable reference value).

FS = Full-scale range of the transmitter or transducer being tested (in milliamperes, inches of water, psi, or degrees, consistent with the units of measure of the NIST traceable reference value).

(c) If each transmitter or transducer meets an accuracy of 1.0 percent of its full-scale range at each level tested, the fuel flowmeter accuracy of 2.0 percent is considered to be met at all levels. If, however, one or more of the transmitters or transducers does not meet an accuracy of 1.0 percent of full-scale at a particular level, then the owner or operator may demonstrate that the fuel flowmeter meets the total accuracy specification of 2.0 percent at that level by using one of the following alternative methods. If, at a particular level, the sum of the individual accuracies of the three transducers is less than or equal to 4.0 percent, the fuel flowmeter accuracy specification of 2.0 percent is considered to be met for that level. Or, if at a particular level, the total fuel flowmeter accuracy is 2.0 percent or less, when calculated in accordance with Part 1 of American Gas Association Report No. 3, General Equations and Uncertainty Guidelines, the flowmeter accuracy requirement is considered to be met for that level.

2.1.6.2 Recordkeeping for Transmitter or Transducer Accuracy Results

(a) Record the accuracy of the orifice, nozzle, or venturi meter or its individual transmitters or transducers and keep this information in a file at the site or other location suitable for inspection.

Table D-2—Table of Flowmeter Transmitter or Transducer Accuracy Results

Test number:____ Test completion date: __________ Unit or pipe ID: ______						
Flowmeter serial number: Component/System ID:						
Full-scale value: Units of measure:[3]						
Transducer/Transmitter Type (check one):						
__ Differential Pressure						
__ Static Pressure						
__ Temperature						
Measurement level (percent of full-scale)	**Run number (if multiple runs)[2]**	**Run time (HHMM)**	**Transmitter/transducer input (pre-calibration)**	**Expected transmitter/transducer output (reference)**	**Actual transmitter/transducer output[3]**	**Percent accuracy (percent of full-scale)**
Low (Minimum) level						
__ percent[1] of full-scale						
Mid-level						
__ percent[1] of full-scale						
(If tested at more than 3 levels)						
2nd Mid-level						
__ percent[1] of full-scale						
(If tested at more than 3 levels)						
3rd Mid-level						
__ percent[1] of full-scale						
High (Maximum) level						
__ percent[1] of full-scale						

[1]At a minimum, it is required to test at zero-level and at least two other levels across the range of the transmitter or transducer readings corresponding to normal unit operation.

[2]It is required to test at least once at each level.

[3]Use the same units of measure for all readings (e.g., use degrees (°), inches of water (in H_2O), pounds per square inch (psi), or milliamperes (ma) for both transmitter or transducer readings and reference readings).

(b)-(c) [Reserved]

2.1.6.3 Failure of Transducer(s) or Transmitter(s)

If, during a transmitter or transducer accuracy test conducted according to section 2.1.6.1 of this appendix, the flowmeter accuracy specification of 2.0 percent is not met at any of the levels tested, repair or replace transmitter(s) or transducer(s) as necessary until the flowmeter accuracy specification has been achieved at all levels. (Note that only transmitters or transducers which are repaired or replaced need to be re-tested; however, the re-testing is required at all three measurement levels, to ensure that the flowmeter accuracy specification is met at each level). The fuel flowmeter is "out-of-control" and data from the flowmeter are considered invalid, beginning with the date and hour of the failed accuracy test and continuing until the date and hour of completion of a successful transmitter or transducer accuracy test at all levels. In addition, if, during normal operation of the fuel flowmeter, one or more transmitters or transducers malfunction, data from the fuel flowmeter shall be considered invalid from the hour of the transmitter or transducer failure until the hour of completion of a successful 3-level transmitter or transducer accuracy test. During fuel flowmeter out-of-control periods, provide data from another fuel flowmeter that meets the requirements of §75.20(d) and section 2.1.5 of this appendix, or substitute for fuel flow rate using the missing data procedures in section 2.4.2 of this appendix. Record and report test data and results, consistent with sections 2.1.6.1 and 2.1.6.2 of this appendix and §75.59.

2.1.6.4 Primary Element Inspection

(a) Conduct a visual inspection of the orifice, nozzle, or venturi meter at least once every twelve calendar quarters. Notwithstanding this requirement, the procedures of section 2.1.7 of this appendix may be used to reduce the inspection frequency of the orifice, nozzle, or venturi meter to at least once every twenty calendar quarters. The inspection may be performed using a baroscope. If the visual inspection is failed (if the orifice, nozzle, or venturi meter has become damaged or corroded), then:

(1) Replace the primary element with another primary element meeting the requirements of American Gas Association Report No. 3 or ASME MFC-3M-1989, as cited in section 2.1.5.1 of this appendix (both standards incorporated by reference under §75.6). If the primary element size is changed, also calibrate the transmitters or transducers, consistent with the new primary element size;

(2) Replace the primary element with another primary element, and demonstrate that the overall flowmeter accuracy meets the accuracy specification in section 2.1.5 of this appendix, using the procedures of section 2.1.5.2 of this appendix; or

(3) Restore the damaged or corroded primary element to "as new" condition; determine the overall accuracy of the flowmeter, using either the specifications of American Gas Association Report No. 3 or ASME MFC-3M-1989, as cited in section 2.1.5.1 of this appendix (both standards incorporated by reference under §75.6); and retest the transmitters or transducers prior to providing quality-assured data from the flowmeter.

(b) Data from the fuel flowmeter are considered invalid, beginning with the date and hour of a failed visual inspection and continuing until the date and hour when:

(1) The damaged or corroded primary element is replaced with another primary element meeting the requirements of American Gas Association Report No. 3 or ASME MFC-3M-1989, as cited in section 2.1.5.1 of this appendix (both standards incorporated by reference under §75.6) and, if applicable, the transmitters have been successfully recalibrated;

(2) The damaged or corroded primary element is replaced, and the overall accuracy of the flowmeter is demonstrated to meet the accuracy specification in section 2.1.5 of this appendix, using the procedures of section 2.1.5.2 of this appendix; or

(3) The restored primary element is installed to meet the requirements of American Gas Association Report No. 3 or ASME MFC-3M-1989, as cited in section 2.1.5.1 of this appendix (both standards incorporated by reference under §75.6) and its transmitters or transducers are retested to meet the accuracy specification in section 2.1.6.1 of this appendix.

(c) During each period of invalid fuel flowmeter data described in paragraph (b) of this section, provide data from another fuel flowmeter that meets the requirements of §75.20(d) and section 2.1.5 of this appendix, or substitute for fuel flow rate using the missing data procedures in section 2.4.2 of this appendix.

2.1.7 Fuel Flow-to-Load Quality Assurance Testing for Certified Fuel Flowmeters

The procedures of this section may be used as an optional supplement to the quality assurance procedures in section 2.1.5.1, 2.1.5.2, 2.1.6.1, or 2.1.6.4 of this appendix when conducting periodic quality assurance testing of a certified fuel flowmeter. Note, however, that these procedures may not be used unless the 168-hour baseline data requirement of section 2.1.7.1 of this appendix has been met. If, following a flowmeter accuracy test or (if applicable) a flowmeter transmitter test and primary element inspection, the procedures of this section are performed during each subsequent fuel flowmeter QA operating quarter, as defined in §72.2 of this chapter (excluding the quarter(s) in which the baseline data are collected), then these procedures may be used to meet the requirement for periodic quality assurance for a period of up to 20 calendar quarters from the previous periodic quality assurance procedure(s) performed according to sections 2.1.5.1, 2.1.5.2, or 2.1.6.1 through 2.1.6.4 of this appendix. The procedures of this section are not required for any quarter in which a flowmeter accuracy test or (if applicable) a transmitter accuracy test and a primary element inspection, are conducted. Notwithstanding the requirements of §75.57(a), when using the procedures of this section, keep records of the test data and results from the previous flowmeter accuracy test under section 2.1.5.1 or 2.1.5.2 of this appendix, records of the test data and results from the previous transmitter or transducer accuracy test under section 2.1.6.1 of this appendix for orifice-, nozzle-, and venturi-type fuel flowmeters, and records of the previous visual inspection of the primary element required under section 2.1.6.4 of this appendix for orifice-, nozzle-, and venturi-type fuel flowmeters until the next flowmeter accuracy test, transmitter accuracy test, or visual inspection is performed, even if the previous flowmeter accuracy test, transmitter accuracy test, or visual inspection was performed more than three years previously.

2.1.7.1 Baseline Flow Rate-to-Load Ratio or Heat Input-to-Load Ratio

(a) Determine R_{base}, the baseline value of the ratio of fuel flow rate to unit load, following each successful periodic quality assurance procedure performed according to sections 2.1.5.1, 2.1.5.2, or 2.1.6.1 and 2.1.6.4 of this appendix. Establish a baseline period of data consisting, at a minimum, of 168 hours of quality-assured fuel flowmeter data. Baseline data collection shall begin with the first hour of fuel flowmeter operation following completion of the most recent quality assurance procedure(s), during which only the fuel measured by the fuel flowmeter is combusted (e.g., only gas, only residual oil, or only diesel fuel is combusted by the unit). During the baseline data collection period, the owner or operator may exclude as non-representative any hour in which the unit is "ramping" up or down, (i.e., the load during the hour differs by more than 15.0 percent from the load in the previous or subsequent hour) and may exclude any hour in which the unit load is in the lower 25.0 percent of the range of operation, as defined in section 6.5.2.1 of appendix A to this part (unless operation in this lower 25.0 percent of the range is considered normal for the unit). The baseline data must be obtained no later than the end of the fourth calendar quarter following the calendar quarter of the most recent quality assurance procedure for that fuel flowmeter. For orifice-, nozzle-, and venturi-type fuel flowmeters, if the fuel flow-to-load ratio is to be used as a supplement both to the transmitter accuracy test under section 2.1.6.1 of this appendix and to primary element inspections under section 2.1.6.4 of this appendix, then the baseline data must be obtained after both procedures are completed and no later than the end of the fourth calendar quarter following the calendar quarter in which both procedures were completed. From these 168 (or more) hours of baseline data, calculate the baseline fuel flow rate-to-load ratio as follows:

$$R_{base} = \frac{Q_{base}}{L_{avg}} \qquad (Eq.\ \text{D-1b})$$

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where:

R_{base} = Value of the fuel flow rate-to-load ratio during the baseline period; 100 scfh/MWe, 100 scfh/klb per hour steam load, or 100 scfh/mmBtu per hour thermal output for gas-firing; (lb/hr)/MWe, (lb/hr)/klb per hour steam load, or (lb/hr)/mmBtu per hour thermal output for oil-firing.

Q_{base} = Arithmetic average fuel flow rate measured by the fuel flowmeter during the baseline period, 100 scfh for gas-firing and lb/hr for oil-firing.

L_{avg} = Arithmetic average unit load during the baseline period, megawatts, 1000 lb/hr of steam, or mmBtu/hr thermal output.

(b) In Equation D-1b, for a fuel flowmeter installed on a common pipe header, L_{avg} is the sum of the operating loads of all units that received fuel through the common pipe header during the baseline period, divided by the total number of hours of fuel flow rate data collected during the baseline period. For a unit that receives the same type of fuel through multiple pipes, Q_{base} is the sum of the fuel flow rates during the baseline period from all of the pipes, divided by the total number of hours of fuel flow rate data collected during the baseline period. Round off the value of R_{base} to the nearest tenth.

(c) Alternatively, a baseline value of the gross heat rate (GHR) may be determined in lieu of R_{base}. The baseline value of the GHR, GHR_{base}, shall be determined as follows:

$$(GHR)_{base} = \frac{(Heat\ \text{Input})_{avg}}{L_{avg}} \times 1000 \qquad (Eq.\ \text{D-1c})$$

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Where:

$(GHR)_{base}$ = Baseline value of the gross heat rate during the baseline period, Btu/kwh, Btu/lb steam load, or 1000mmBtu heat input/mmBtu thermal output.

$(\text{Heat Input})_{avg}$ = Average (mean) hourly heat input rate recorded by the fuel flowmeter during the baseline period, as determined using the average fuel flow rate and the fuel GCV in the applicable equation in appendix F to this part, mmBtu/hr.

L_{avg} = Average (mean) unit load during the baseline period, megawatts, 1000 lb/hr of steam, or mmBtu/hr thermal output.

(d) Report the current value of R_{base} (or GHR_{base}) and the completion date of the associated quality assurance procedure in each electronic quarterly report required under §75.64.

(e) If a unit co-fires different fuels (*e.g.,* oil and natural gas) as its normal mode of operation, the gross heat rate option in paragraph (c) of this section may be used to determine a value of $(GHR)_{base}$, as follows. Derive the baseline data during co-fired hours. Then, use Equation D-1c to calculate $(GHR)_{base}$, making sure that each hourly unit heat input rate used to calculate $(\text{Heat Input})_{avg}$ includes the contribution of each type of fuel.

2.1.7.2 Data Preparation and Analysis

(a) Evaluate the fuel flow rate-to-load ratio (or GHR) for each fuel flowmeter QA operating quarter, as defined in §72.2 of this chapter. At the end of each fuel flowmeter QA operating quarter, use Equation D-1d in this appendix to calculate R_h, the hourly fuel flow-to-load ratio, for every quality-assured hourly average fuel flow rate obtained with a certified fuel flowmeter. Alternatively, the owner or operator may exclude non-representative hours from the data analysis, as described in section 2.1.7.3 of this appendix, prior to calculating the values of R_h.

$$R_h = \frac{Q_h}{L_h} \qquad (Eq.\ \text{D-1d})$$

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where:

R_h = Hourly value of the fuel flow rate-to-load ratio; 100 scfh/MWe, (lb/hr)/MWe, 100 scfh/1000 lb/hr of steam load, (lb/hr)/1000 lb/hr of steam load, 100 scfh/(mmBtu/hr of steam load), or (lb/hr)/(mmBtu/hr thermal output).

Q_h = Hourly fuel flow rate, as measured by the fuel flowmeter, 100 scfh for gas-firing or lb/hr for oil-firing.

L_h = Hourly unit load, megawatts, 1000 lb/hr of steam, or mmBtu/hr thermal output.

(b) For a fuel flowmeter installed on a common pipe header, Lh shall be the sum of the hourly operating loads of all units that receive fuel through the common pipe header. For a unit that receives the same type of fuel through multiple pipes, Q_h will be the sum of the fuel flow rates from all of the pipes. Round off each value of R_h to the nearest tenth.

(c) Alternatively, calculate the hourly gross heat rates (GHR) in lieu of the hourly flow-to-load ratios. If this option is selected, calculate each hourly GHR value as follows:

$$(GHR)_h = \frac{(\text{Heat Input})_h}{L_h} \times 1000 \qquad (Eq.\ \text{D-1e})$$

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Where:

$(GHR)_h$ = Hourly value of the gross heat rate, Btu/kwh, Btu/lb steam load, or mmBtu heat input/mmBtu thermal output.

$(\text{Heat Input})_h$ = Hourly heat input rate, as determined using the hourly fuel flow rate and the fuel GCV in the applicable equation in appendix F to this part, mmBtu/hr.

L_h = Hourly unit load, megawatts, 1000 lb/hr of steam, or mmBtu/hr thermal output.

(d) Evaluate the calculated flow rate-to-load ratios (or gross heat rates) as follows.

(1) Perform a separate data analysis for each fuel flowmeter system following the procedures of this section. Base each analysis on a minimum of 168 hours of data. If, for a particular fuel flowmeter system, fewer than 168 hourly flow-to-load ratios (or GHR values) are available, or, if the baseline data collection period is still in progress at the end of the quarter and fewer than four calendar quarters have elapsed since the quarter in which the last successful fuel flowmeter system accuracy test was performed, a flow-to-load (or GHR) evaluation is not required for that flowmeter system for that calendar quarter. A one-quarter extension of the deadline for the next fuel flowmeter system accuracy test may be claimed for a quarter in which there is insufficient hourly data available to analyze or a quarter that ends with the baseline data collection period still in progress.

(2) For a unit that normally co-fires different types of fuel (e.g., oil and natural gas), include the contribution of each type of fuel in the value of $(\text{Heat Input})_h$, when using Equation D-1e.

(e) For each hourly flow-to-load ratio or GHR value, calculate the percentage difference (percent D_h) from the baseline fuel flow-to-load ratio using Equation D-1f.

$$\%D_h = \frac{\left|R_{base} - R_h\right|}{R_{base}} \times 100 \quad (Eq.\ D\text{-}1f)$$

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Where:

$\%D_h$ = Absolute value of the percentage difference between the hourly fuel flow rate-to-load ratio and the baseline value of the fuel flow rate-to-load ratio (or hourly and baseline GHR).

R_h = The hourly fuel flow rate-to-load ratio (or GHR).

R_{base} = The value of the fuel flow rate-to-load ratio (or GHR) from the baseline period, determined in accordance with section 2.1.7.1 of this appendix.

(f) Consistently use R_{base} and R_h in Equation D-1f if the fuel flow-to-load ratio is being evaluated, and consistently use $(GHR)_{base}$ and $(GHR)_h$ in Equation D-1f if the gross heat rate is being evaluated.

(g) Next, determine the arithmetic average of all of the hourly percent difference (percent D_h) values using Equation D-1g, as follows:

$$E_f = \sum_{h=1}^{q} \frac{\%D_h}{q} \quad (Eq.\ D\text{-}1g)$$

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Where:

E_f = Quarterly average percentage difference between hourly flow rate-to-load ratios and the baseline value of the fuel flow rate-to-load ratio (or hourly and baseline GHR).

$\%D_h$ = Percentage difference between the hourly fuel flow rate-to-load ratio and the baseline value of the fuel flow rate-to-load ratio (or hourly and baseline GHR).

q = Number of hours used in fuel flow-to-load (or GHR) evaluation.

(h) When the quarterly average load value used in the data analysis is greater than 50 MWe (or 500 klb steam per hour), the results of a quarterly fuel flow rate-to-load (or GHR) evaluation are acceptable and no further action is required if the quarterly average percentage difference (E_f) is no greater than 10.0 percent. When the arithmetic average of the hourly load values used in the data analysis is ≤50 MWe (or 500 klb steam per hour), the results of the analysis are acceptable if the value of E_f is no greater than 15.0 percent. For units that normally co-fire different types of fuel, if the GHR option is used, apply the test results to each fuel flowmeter system used during the quarter.

2.1.7.3 Optional Data Exclusions

(a) If E_f is outside the limits in section 2.1.7.2(h) of this appendix, the owner or operator may re-examine the hourly fuel flow rate-to-load ratios (or GHRs) that were used for the data analysis and may identify and exclude fuel flow-to-load ratios or GHR values for any non-representative hours, provided that such data exclusions were not previously made under section 2.1.7.2(a) of this appendix. Specifically, the R_h or $(GHR)_h$ values for the following hours may be considered non-representative:

(1) For units that do not normally co-fire fuels, any hour in which the unit combusted another fuel in addition to the fuel measured by the fuel flowmeter being tested; or

(2) Any hour for which the load differed by more than ±15.0 percent from the load during either the preceding hour or the subsequent hour; or

(3) For units that normally co-fire different fuels, any hour in which the unit burned only one type of fuel; or

(4) Any hour for which the unit load was in the lower 25.0 percent of the range of operation, as defined in section 6.5.2.1 of appendix A to this part (unless operation in the lower 25.0 percent of the range is considered normal for the unit).

(b) After identifying and excluding all non-representative hourly fuel flow-to-load ratios or GHR values, analyze the quarterly fuel flow rate-to-load data a second time. If fewer than 168 hourly fuel flow-to-load ratio or GHR values remain after the allowable data exclusions, a fuel flow-to-load ratio or GHR analysis is not required for that quarter, and a one-quarter extension of the fuel flowmeter accuracy test deadline may be claimed.

2.1.7.4 Consequences of Failed Fuel Flow-to-Load Ratio Test

(a) If E_f is outside the applicable limit in section 2.1.7.2(h) of this appendix (after analysis using any optional data exclusions under section 2.1.7.3 of this appendix), perform transmitter accuracy tests according to section 2.1.6.1 of this appendix for orifice-, nozzle-, and venturi-type flowmeters, or perform a fuel flowmeter accuracy test, in accordance with section 2.1.5.1 or 2.1.5.2 of this appendix, for each fuel flowmeter for which E_f is outside of the applicable limit. In addition, for an orifice-, nozzle-, or venturi-type fuel flowmeter, repeat the fuel flow-to-load ratio comparison of section 2.1.7.2 of this appendix using six to twelve hours of data following a passed transmitter accuracy test in order to verify that no significant corrosion has affected the primary element. If, for the abbreviated 6-to-12 hour test, the orifice-, nozzle-, or venturi-type fuel flowmeter is not able to meet the limit in section 2.1.7.2 of this appendix, then perform a visual inspection of the primary element according to section 2.1.6.4 of this appendix, and repair or replace the primary element, as necessary.

(b) Substitute for fuel flow rate, for any hour when that fuel is combusted, using the missing data procedures in section 2.4.2 of this appendix, beginning with the first hour of the calendar quarter following the quarter for which E_f was found to be outside the applicable limit and continuing until quality-assured fuel flow data become available. Following a failed flow rate-to-load or GHR evaluation, data from the flowmeter shall not be considered quality-assured until the hour in which all required flowmeter accuracy tests, transmitter accuracy tests, visual inspections and diagnostic tests have been passed. Additionally, a new value of R_{base} or $(GHR)_{base}$ shall be established no later than two fuel flowmeter QA operating quarters (as defined in §72.2 of this chapter) after the quarter in which the required quality assurance tests are completed (note that for orifice-, nozzle-, or venturi-type fuel flowmeters, establish a new value of R_{base} or $(GHR)_{base}$ only if both a transmitter accuracy test and a primary element inspection have been performed).

2.1.7.5 Test Results

Report the results of each quarterly flow rate-to-load (or GHR) evaluation, as determined from Equation D-1g, in the electronic quarterly report required under §75.64. Table D-3 is provided as a reference on the type of information to be recorded under §75.59 and reported under §75.64.

TABLE D-3—BASELINE INFORMATION AND TEST RESULTS FOR FUEL FLOW-TO-LOAD TEST

Plant name:________________ State:____ ORIS code:____________

Unit/pipe ID #:__________ Fuel flowmeter system ID :___ Calendar quarter (1st, 2nd, 3rd, 4th) and year:_________

Range of operation: _______ to _______ MWe or klb steam/hr (indicate units)

Reported Data Elements	
Baseline period	Quarterly analysis
Completion date and time of most recent QA sequence, i.e., primary element inspection and transmitter calibration (orifice-, nozzle-, and venturi-type flowmeters only). __/__/__ __:__	Number of hours excluded from quarterly average due to co-firing different fuels (where co-firing is not normal operation):______ hrs.
Completion date and time of most recent flowmeter or accuracy test (all other flowmeters) __/__/__ __:__	Number of hours excluded from quarterly average due to single-fuel combustion (where co-firing is normal operation):______ hrs.
Beginning date and time of baseline period __/__/__ __:__	Number of hours excluded from quarterly average due to ramping load:______ hrs.
End date and time of baseline period __/__/__ __:__	Number of hours in the lower 25.0 percent of the range of operation excluded from quarterly average: ______hrs.
Average fuel flow rate______________ (100 scfh for gas and lb/hr for oil)	Number of hours included in quarterly average:______ hrs.
	Quarterly percentage difference between hourly ratios and baseline ratio:______ percent.
Average load;______________ (MWe or 1000 lb steam/hr)	Test result: pass, fail.
Baseline fuel flow-to-load ratio ________ Units of fuel flow-to-load:________	
Baseline GHR: ______ Units of fuel flow-to-load:________	
Number of hours excluded from baseline ratio or GHR due to ramping load: ______	
Number of hours in the lower 25.0 percent of the range of operation excluded from baseline ratio or GHR: ______hrs.	

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2.2 Oil Sampling and Analysis

Perform sampling and analysis of oil to determine the following fuel properties for each type of oil combusted by a unit: percentage of sulfur by weight in the oil; gross calorific value (GCV) of the oil; and, if necessary, the density of the oil. Use the sulfur content, density, and gross calorific value, determined under the provisions of this section, to calculate SO_2 mass emission rate and heat input rate for each fuel using the applicable procedures of section 3 of this appendix. The designated representative may petition for reduced GCV and or density sampling under §75.66 if the fuel combusted has a consistent and relatively non-variable GCV or density.

TABLE D-4. -- OIL SAMPLING METHODS AND SULFUR, DENSITY AND GROSS CALORIFIC VALUE USED IN CALCULATIONS

Parameter	Sampling technique/frequency	Value used in calculations (except for missing data hours)
Oil Sulfur Content	Daily manual sampling	1. Highest sulfur content from previous 30 daily samples; or 2. Actual daily value.
	Flow proportional/weekly composite	Actual measured value.
	In storage tank (after addition of fuel to tank)	1. Actual measured value; or 2. Highest of all sampled values in previous calendar year, unless a higher sample value is obtained;[1] or 3. Maximum value allowed by contract, unless a higher sample value is obtained[1]
	As delivered (in delivery truck or barge).[1]	1. Highest of all sampled values in previous calendar year, unless a higher sample value is obtained;[1] or 2. Maximum value allowed by contract, unless a higher sample value is obtained[1]
Oil Density	Daily manual sampling	1. Use the highest density from the previous 30 daily samples; or 2. Actual measured value.
	Flow proportional/weekly composite	Actual measured value.
	In storage tank (after addition of fuel to tank)	1. Actual measured value; or 2. Highest of all sampled values in previous calendar year, unless a higher sample value is obtained;[1] or 3. Maximum value allowed by contract, unless a higher sample value is obtained[1]
	As delivered (in delivery truck or barge).[1]	1. Highest of all sampled values in previous calendar year, unless a higher sample value is obtained;[1] or 2. Maximum value allowed by contract, unless a higher sample value is obtained[1]
Oil GCV	Daily manual sampling	1. Highest fuel GCV from the previous 30 daily samples; or 2. Actual measured value.
	Flow proportional/weekly composite	Actual measured value.
	In storage tank (after addition of fuel to tank)	1. Actual measured value; or 2. Highest of all sampled values in previous calendar year, unless a higher sample value is obtained;[1] or 3. Maximum value allowed by contract, unless a higher sample value is obtained[1]
	As delivered (in delivery truck or barge).[1]	1. Highest of all sampled values in previous calendar year, unless a higher sample value is obtained;[1] or 2. Maximum value allowed by contract, unless a higher sample value is obtained[1]

1/ Assumed values may only be used if sulfur content, gross calorific value, or density of each sample is no greater than the assumed value used to calculate emissions or heat input. If a higher sample value is obtained, use the results of that sample analysis as the new assumed value.

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2.2.1 When combusting oil, use one of the following methods to sample the oil (see Table D-4): sample from the storage tank for the unit after each addition of oil to the storage tank, in accordance with section 2.2.4.2 of this appendix; or sample from the fuel lot in the shipment tank or container upon receipt of each oil delivery or from the fuel lot in the oil supplier's storage container, in accordance with section 2.2.4.3 of this appendix; or use the flow proportional sampling methodology in section 2.2.3 of this appendix; or use the daily manual sampling methodology in section 2.2.4.1 of this appendix. For purposes of this appendix, a fuel lot of oil is the mass or volume of product oil from one source (supplier or pretreatment facility), intended as one shipment or delivery (e.g., ship load, barge load, group of trucks, discrete purchase of diesel fuel through pipeline, etc.). A storage tank is a container at a plant holding oil that is actually combusted by the unit, such that no blending of any other fuel with the fuel in the storage tank occurs from the time that the fuel lot is transferred to the storage tank to the time when the fuel is combusted in the unit.

2.2.2 [Reserved]

2.2.3 Flow Proportional Sampling

Conduct flow proportional oil sampling or continuous drip oil sampling in accordance with ASTM D4177-95 (Reapproved 2000), “Standard Practice for Automatic Sampling of Petroleum and Petroleum Products” (incorporated by reference under

§75.6), every day the unit is combusting oil. Extract oil at least once every hour and blend into a composite sample. The sample compositing period may not exceed 7 calendar days (168 hrs). Use the actual sulfur content (and where density data are required, the actual density) from the composite sample to calculate the hourly SO_2 mass emission rates for each operating day represented by the composite sample. Calculate the hourly heat input rates for each operating day represented by the composite sample, using the actual gross calorific value from the composite sample.

2.2.4 Manual Sampling

2.2.4.1 Daily Samples

Representative oil samples may be taken from the storage tank or fuel flow line manually every day that the unit combusts oil according to ASTM ASTM D4057-95 (Reapproved 2000), Standard Practice for Manual Sampling of Petroleum and Petroleum Products (incorporated by reference under §75.6 of this part). Use either the actual daily sulfur content or the highest fuel sulfur content recorded at that unit from the most recent 30 daily samples for the purpose of calculating SO_2 emissions under section 3 of this appendix. Use either the gross calorific value measured from that day's sample or the highest GCV from the previous 30 days' samples to calculate heat input. If oil supplies with different sulfur contents are combusted on the same day, sample the highest sulfur fuel combusted that day.

2.2.4.2 Sampling From a Unit's Storage Tank

Take a manual sample after each addition of oil to the storage tank. Do not blend additional fuel with the sampled fuel prior to combustion. Sample according to the single tank composite sampling procedure or all-levels sampling procedure in ASTM ASTM D4057-95 (Reapproved 2000), Standard Practice for Manual Sampling of Petroleum and Petroleum Products (incorporated by reference under §75.6 of this part). Use the sulfur content and GCV value (and where required, the density) of either the most recent sample or one of the conservative assumed values described in section 2.2.4.3(c) of this appendix to calculate SO_2 mass emission rate. Calculate heat input rate using the gross calorific value from either:

(a) The most recent oil sample taken or

(b) One of the conservative assumed values described in section 2.2.4.3(c) of this appendix. Follow the applicable provisions in section 2.2.4.3(d) of this appendix, regarding the use of assumed values.

2.2.4.3 Sampling From Each Delivery

(a) Alternatively, an oil sample may be taken from—

(1) The shipment tank or container upon receipt of each lot of fuel oil or

(2) The supplier's storage container which holds the lot of fuel oil. (Note: a supplier need only sample the storage container once for sulfur content, GCV and, where required, the density so long as the fuel sulfur content and GCV do not change and no fuel is added to the supplier's storage container.)

(b) For the purpose of this section, a lot is defined as a shipment or delivery (e.g., ship load, barge load, group of trucks, discrete purchase of diesel fuel through a pipeline, etc.) of a single fuel.

(c) Oil sampling may be performed either by the owner or operator of an affected unit, an outside laboratory, or a fuel supplier, provided that samples are representative and that sampling is performed according to either the single tank composite sampling procedure or the all-levels sampling procedure in ASTM ASTM D4057-95 (Reapproved 2000), Standard Practice for Manual Sampling of Petroleum and Petroleum Products (incorporated by reference under §75.6 of this part). Except as otherwise provided in this section, calculate SO_2 mass emission rate using the sulfur content (and where required, the density) from one of the two following conservative assumed values, and calculate heat input using the gross calorific value from one of the assumed values:

(1) The highest value sampled during the previous calendar year (this option is allowed for any consistent fuel which comes from a single source whether or not the fuel is supplied under a contractual agreement) or

(2) The maximum value indicated in the contract with the fuel supplier. Continue to use this assumed contract value unless and until the actual sampled sulfur content, density, or gross calorific value of a delivery exceeds the assumed value.

(d) Continue using the assumed value(s), so long as the sample results do not exceed the assumed value(s). However, if the actual sampled sulfur content, gross calorific value, or density of an oil sample is greater than the assumed value for that parameter, then, consistent with section 2.3.7 of this appendix, begin to use the actual sampled value for sulfur content, gross calorific value, or density of fuel to calculate SO2 mass emission rate or heat input rate. Consider the sampled value to be the new assumed sulfur content, gross calorific value, or density. Continue using this new assumed value to calculate SO2 mass emission rate or heat input rate unless and until: it is superseded by a higher value from an oil sample; or (if applicable) it is superseded by a new contract in which case the new contract value becomes the assumed value at the time the fuel specified under the new contract begins to be combusted in the unit; or (if applicable) both the calendar year in which the sampled value exceeded the assumed value and the subsequent calendar year have elapsed.

2.2.5 For each oil sample that is taken on-site at the affected facility, split and label the sample and maintain a portion (at least 200 cc) of it throughout the calendar year and in all cases for not less than 90 calendar days after the end of the calendar year allowance accounting period. This requirement does not apply to oil samples taken from the fuel supplier's storage container, as described in section 2.2.4.3 of this appendix. Analyze oil samples for percent sulfur content by weight in accordance with ASTM D129-00, Standard Test Method for Sulfur in Petroleum Products (General Bomb Method), ASTM D1552-01, Standard Test Method for Sulfur in Petroleum Products (High-Temperature Method), ASTM D2622-98, Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-ray Fluorescence Spectrometry, ASTM D4294-98, Standard Test Method for Sulfur in Petroleum and Petroleum Products by Energy-Dispersive X-ray Fluorescence Spectrometry, or ASTM D5453-06, Standard Test Method for Determination of Total Sulfur in Light Hydrocarbons, Spark Ignition Engine Fuel, Diesel Engine Fuel, and Engine Oil by Ultraviolet Fluorescence (all incorporated by reference under §75.6 of this part). Alternatively, the oil samples may be analyzed for percent sulfur by any consensus standard method prescribed for the affected unit under part 60 of this chapter.

2.2.6 Where the flowmeter records volumetric flow rate rather than mass flow rate, analyze oil samples to determine the density or specific gravity of the oil. Determine the density or specific gravity of the oil sample in accordance with ASTM D287-92 (Reapproved 2000), Standard Test Method for API Gravity of Crude Petroleum and Petroleum Products (Hydrometer Method), ASTM D1217-93 (Reapproved 1998), Standard Test Method for Density and Relative Density (Specific Gravity) of Liquids by Bingham Pycnometer, ASTM D1481-93 (Reapproved 1997), Standard Test Method for Density and Relative Density (Specific Gravity) of Viscous Materials by Lipkin Bicapillary Pycnometer, ASTM D1480-93 (Reapproved 1997), Standard Test Method for Density and Relative Density (Specific Gravity) of Viscous Materials by Bingham Pycnometer, ASTM D1298-99, Standard Test Method for Density, Relative Density (Specific Gravity), or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method, or ASTM D4052-96 (Reapproved 2002), Standard Test Method for Density and Relative Density of Liquids by Digital Density Meter (all incorporated by reference under §75.6 of this part). Alternatively, the oil samples may be analyzed for density or specific gravity by any consensus standard method prescribed for the affected unit under part 60 of this chapter.

2.2.7 Analyze oil samples to determine the heat content of the fuel. Determine oil heat content in accordance with ASTM D240-00, ASTM D4809-00, ASTM D5865-01a, or D5865-10 (all incorporated by reference under §75.6) or any other procedures listed in section 5.5 of appendix F of this part. Alternatively, the oil samples may be analyzed for heat content by any consensus standard method prescribed for the affected unit under part 60 of this chapter.

2.2.8 Results from the oil sample analysis 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 of the analysis be available as soon as practicable, and no later than 5 business days after receipt of a request from the Administrator.

2.3 SO_2 Emissions From Combustion of Gaseous Fuels

(a) Account for the hourly SO_2 mass emissions due to combustion of gaseous fuels for each hour when gaseous fuels are combusted by the unit using the procedures in this section.

(b) The procedures in sections 2.3.1 and 2.3.2 of this appendix, respectively, may be used to determine SO_2 mass emissions from combustion of pipeline natural gas and natural gas, as defined in §72.2 of this chapter. The procedures in section 2.3.3 of this appendix may be used to account for SO_2 mass emissions from any gaseous fuel combusted by a unit. For each type of gaseous fuel, the appropriate sampling frequency and the sulfur content and GCV values used for calculations of SO_2 mass emission rates are summarized in the following Table D-5.

TABLE D-5. -- GAS SULFUR AND GCV VALUES USED IN CALCULATIONS FOR VARIOUS FUEL TYPES

Parameter	Fuel type and sampling frequency	Value used in calculations (except for missing data hours)
Gas Total Sulfur Content	Pipeline Natural Gas with total sulfur content less than or equal to 0.5 grains/100scf * Sampling is not required if a valid contract or tariff sheet is used to qualify. * If fuel sampling and analysis is used to qualify, sample annually and whenever the fuel supply source changes.	1. If a contract or tariff sheet is used to qualify, use 0.0006 lb/mmBtu 2. If fuel sampling and analysis is used to qualify, use 0.0006 lb/mmBtu, provided that the results of the required annual samples do not exceed 0.5 grains/100 scf of total sulfur. If the results of an annual sample exceed 0.5 grains/100 scf, re-classify the fuel as appropriate and determine the SO_2 emission rate to be used in the calculations, using the applicable procedures in section 2.3.2 or 2.3.3 of this appendix
	Natural Gas with total sulfur content less than or equal to 20.0 grains /100scf * Sampling is not required if a valid contract or tariff sheet is used to qualify. * If fuel sampling and analysis is used to qualify, sample annually and whenever the fuel supply source changes.	Default SO_2 emission rate calculated from Eq. D-1h, using either: 1. The maximum total sulfur content specified in the fuel contract or tariff sheet, if a contract or tariff sheet is used to qualify; or 2. The total sulfur content, based on the most recent fuel sampling and analysis. If multiple samples are taken, the results may be averaged before using Equation D-1h.
	Any gaseous fuel transmitted by pipeline, having a "low sulfur variability", as shown under section 2.3.6 of this appendix. * Either sample daily or, if Eq. D-1h is used to calculate a default SO_2 emission rate, sample annually.	* If daily sampling is performed, use either: 1. Actual value from the daily sample; or 2. Highest value from previous 30 samples. * If the option to use Eq. D-1h is selected, use a default SO_2 emission rate, calculated using the higher of: 1. The 90^{th} percentile value of the total sulfur content, obtained in the 720-hr demonstration under section 2.3.6; or 2. The actual total sulfur content from the most recent annual sample. If multiple samples are taken, the results may be averaged before using Equation D-1h.

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Parameter	Fuel type and sampling frequency	Value used in calculations (except for missing data hours)
	Any gaseous fuel transmitted by pipeline, having a maximum total sulfur content ≤ 20 grains/100 scf and "high sulfur variability", as shown under section 2.3.6 of this appendix. * Either sample hourly or, if Eq. D-1h is used to calculate a default SO_2 emission rate, sample annually.	* If hourly sampling is performed, use the actual hourly value * If the option to use Eq. D-1h is selected, use a default SO_2 emission rate, calculated using the higher of: 1. The maximum value of the total sulfur content, obtained in the 720-hr demonstration under section 2.3.6; or 2. The actual total sulfur content from the most recent annual sample. If multiple samples are taken, the results may be averaged before using Equation D-1h.
	Any gaseous fuel transmitted by pipeline, having a maximum total sulfur content > 20 grains/100 scf and "high sulfur variability", as shown under section 2.3.6 of this appendix. * Sample hourly	Actual hourly sulfur content of the gas
	Any gaseous fuel delivered in shipments or lots * Sample each lot or shipment.	1. Actual total sulfur content from most recent shipment; or 2. Highest total sulfur content from previous year's samples, unless a higher value is obtained in a sample[1] ; or 3. Maximum total sulfur content value allowed by contract, unless a higher value is obtained in a sample.[1]
Gas GCV	Pipeline Natural Gas * Sample monthly	1. GCV from most recent monthly sample (with ≥ 48 operating hours in the month); 2. Maximum GCV from contract, unless a higher value is obtained in a monthly sample;[1] or 3. Highest GCV from previous year's samples, unless a higher value is obtained in a monthly sample.[1]
	Natural Gas * Sample monthly	1. GCV from most recent monthly sample (with ≥ 48 operating hours in the month); 2. Maximum GCV from contract[1] or 3. Highest GCV from previous year's samples.[1]
	Any gaseous fuel delivered in shipments or lots * Sample each lot or shipment	1. Actual GCV from most recent shipment or lot; 2. Highest GCV from previous year's samples, unless a higher value is obtained in a sample;[1] or 3. Maximum GCV value allowed by contract, unless a higher value is obtained in a sample.[1]

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Parameter	Fuel type and sampling frequency	Value used in calculations (except for missing data hours)
	Any gaseous fuel transmitted by pipeline and having a demonstrated "low GCV variability" using the provisions of section 2.3.5 * Sample monthly	1. GCV from most recent monthly sample (with ≥ 48 operating hours in the month); or 2. Highest GCV from previous year's samples, unless a higher value is obtained in a monthly sample.[1]
	Any gaseous fuel not demonstrated to have a "low GCV variability" under section 2.3.5 * Sample daily or hourly. (Note that the use of an on-line GCV calorimeter or gas chromatograph is allowed).	Actual daily or hourly GCV of the gas.

[1] Assumed sulfur content and GCV values (i.e., contract values or highest values from previous year) may only continue to be used if the sulfur content or GCV of each sample is no greater than the assumed value used to calculate SO_2 emissions or heat input. If a higher sample value is obtained, use the results of that sample analysis as the new assumed value.

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2.3.1 Pipeline Natural Gas Combustion

The owner or operator may determine the SO_2 mass emissions from the combustion of a fuel that meets the definition of pipeline natural gas, in §72.2 of this chapter, using the procedures of this section.

2.3.1.1 SO_2 Emission Rate

For a fuel that meets the definition of pipeline natural gas under §72.2 of this chapter, the owner or operator may determine the SO_2 mass emissions using either a default SO_2 emission rate of 0.0006 lb/mmBtu and the procedures of this section, the procedures in section 2.3.2 for natural gas, or the procedures of section 2.3.3 for any gaseous fuel. For each affected unit using the default rate of 0.0006 lb/mmBtu, the owner or operator must document that the fuel combusted is actually pipeline natural gas, using the procedures in section 2.3.1.4 of this appendix.

2.3.1.2 Hourly Heat Input Rate

Calculate hourly heat input rate, in mmBtu/hr, for a unit combusting pipeline natural gas, using the procedures of section 3.4.1 of this appendix. Use the measured fuel flow rate from section 2.1 of this appendix and the gross calorific value from section 2.3.4.1 of this appendix in the calculations.

2.3.1.3 SO_2 Hourly Mass Emission Rate and Hourly Mass Emissions

For pipeline natural gas combustion, calculate the SO2 mass emission rate, in lb/hr, using Equation D-5 in section 3.3.2 of this appendix (when the default SO_2 emission rate is used) or Equation D-4 (if daily or hourly fuel sampling is used). Then, use the calculated SO_2 mass emission rate and the unit operating time to determine the hourly SO_2 mass emissions from pipeline natural gas combustion, in lb, using Equation D-12 in section 3.5.1 of this appendix.

2.3.1.4 Documentation that a Fuel is Pipeline Natural Gas

(a) A fuel may initially qualify as pipeline natural gas, if information is provided in the monitoring plan required under §75.53, demonstrating that the definition of pipeline natural gas in §72.2 of this chapter has been met. The information must demonstrate that the fuel meets either the percent methane or GCV requirement and has a total sulfur content of 0.5 grains/100scf or less. The demonstration must be made using one of the following sources of information:

(1) The gas quality characteristics specified by a purchase contract, tariff sheet, or by a pipeline transportation contract; or

(2) Historical fuel sampling data for the previous 12 months, documenting the total sulfur content of the fuel and the GCV and/or percentage by volume of methane. The results of all sample analyses obtained by or provided to the owner or operator in the previous 12 months shall be used in the demonstration, and each sample result must meet the definition of pipeline natural gas in §72.2 of this chapter, except where the results of at least 100 daily (or more frequent) total sulfur samples are provided by the fuel supplier. In that case you may opt to convert these data to monthly averages and then if, for each month, the average total sulfur content is 0.5 grains/100 scf or less, and if the GCV or percent methane requirement is also met, the fuel qualifies as pipeline natural gas. Alternatively, the fuel qualifies as pipeline natural gas if ≥98 percent of the 100 (or more) samples have a total sulfur content of 0.5 grains/100 scf or less and if the GCV or percent methane requirement is also met; or

(3) If the requirements of paragraphs (a)(1) and (a)(2) of this section cannot be met, a fuel may initially qualify as pipeline natural gas if at least one representative sample of the fuel is obtained and analyzed for total sulfur content and for either the gross calorific value (GCV) or percent methane, and the results of the sample analysis show that the fuel meets the definition of pipeline natural gas in §72.2 of this chapter. Use the sampling methods specified in sections 2.3.3.1.2 and 2.3.4 of this

appendix. The required fuel sample may be obtained and analyzed by the owner or operator, by an independent laboratory, or by the fuel supplier. If multiple samples are taken, each sample must meet the definition of pipeline natural gas in §72.2 of this chapter.

(b) If the results of the fuel sampling under paragraph (a)(2) or (a)(3) of this section show that the fuel does not meet the definition of pipeline natural gas in §72.2 of this chapter, but those results are believed to be anomalous, the owner or operator may document the reasons for believing this in the monitoring plan for the unit, and may immediately perform additional sampling. In such cases, a minimum of three additional samples must be obtained and analyzed, and the results of each sample analysis must meet the definition of pipeline natural gas.

(c) If several affected units are supplied by a common source of gaseous fuel, a single sampling result may be applied to all of the units and it is not necessary to obtain a separate sample for each unit, provided that the composition of the fuel is not altered by blending or mixing it with other gaseous fuel(s) when it is transported from the sampling location to the affected units. For the purposes of this paragraph, the term "other gaseous fuel(s)" excludes compounds such as mercaptans when they are added in trace quantities for safety reasons.

(d) If the results of fuel sampling and analysis under paragraph (a)(2), (a)(3), or (b) of this section show that the fuel does not qualify as pipeline natural gas, proceed as follows:

(1) If the fuel still qualifies as natural gas under section 2.3.2.4 of this appendix, re-classify the fuel as natural gas and determine the appropriate default SO_2 emission rate for the fuel, according to section 2.3.2.1.1 of this appendix; or

(2) If the fuel does not qualify either as pipeline natural gas or natural gas, re-classify the fuel as "other gaseous fuel" and implement the procedures of section 2.3.3 of this appendix, within 180 days of the end of the quarter in which the disqualifying sample was taken. In addition, the owner or operator shall use Equation D-1h in this appendix to calculate a default SO_2 emission rate for the fuel, based on the results of the sample analysis that exceeded 20 grains/100 scf of total sulfur, and shall use that default emission rate to report SO_2 mass emissions under this part until section 2.3.3 of this appendix has been fully implemented.

(e) If a fuel qualifies as pipeline natural gas based on the specifications in a fuel contract or tariff sheet, no additional, on-going sampling of the fuel's total sulfur content is required, provided that the contract or tariff sheet is current, valid and representative of the fuel combusted in the unit. If the fuel qualifies as pipeline natural gas based on fuel sampling and analysis, on-going sampling of the fuel's sulfur content is required annually and whenever the fuel supply source changes. For the purposes of this paragraph (e), sampling "annually" means that at least one sample is taken in each calendar year. If the results of at least 100 daily (or more frequent) total sulfur samples have been provided by the fuel supplier since the last annual assessment of the fuel's sulfur content, the data may be used as follows to satisfy the annual sampling requirement for the current year. If this option is chosen, all of the data provided by the fuel supplier shall be used. First, convert the data to monthly averages. Then, if, for each month, the average total sulfur content is 0.5 grains/100 scf or less, and if the GCV or percent methane requirement is also met, the fuel qualifies as pipeline natural gas. Alternatively, the fuel qualifies as pipeline natural gas if the analysis of the 100 (or more) total sulfur samples since the last annual assessment shows that ≥98 percent of the samples have a total sulfur content of 0.5 grains/100 scf or less and if the GCV or percent methane requirement is also met. The effective date of the annual total sulfur sampling requirement is January 1, 2003.

(f) On-going sampling of the GCV of the pipeline natural gas is required under section 2.3.4.1 of this appendix.

(g) For units that are required to monitor and report NO_X mass emissions and heat input under subpart H of this part, but which are not affected units under the Acid Rain Program, the owner or operator is exempted from the requirements in paragraphs (a) and (e) of this section to document the total sulfur content of the pipeline natural gas.

2.3.2 Natural Gas Combustion

The owner or operator may determine the SO_2 mass emissions from the combustion of a fuel that meets the definition of natural gas, in §72.2 of this chapter, using the procedures of this section.

2.3.2.1 SO_2 Emission Rate

The owner or operator may account for SO_2 emissions either by using a default SO_2 emission rate, as determined under section 2.3.2.1.1 of this appendix, or by daily sampling of the gas sulfur content using the procedures of section 2.3.3 of this appendix. For each affected unit using a default SO_2 emission rate, the owner or operator must provide documentation that the fuel combusted is actually natural gas according to the procedures in section 2.3.2.4 of this appendix.

2.3.2.1.1 In lieu of daily sampling of the sulfur content of the natural gas, the owner or operator may either use the total sulfur content specified in a contract or tariff sheet as the SO_2 default emission rate or may calculate the default SO_2 emission rate based on fuel sampling results, using Equation D-1h. In Equation D-1h, the total sulfur content and GCV values shall be determined in accordance with Table D-5 of this appendix. Round off the calculated SO_2 default emission rate to the nearest 0.0001 lb/mmBtu.

$$ER = \left[\frac{2.0}{7000}\right] \times \left[10^6\right] \times \left[\frac{S_{total}}{GCV}\right] \qquad (Eq.\ D\text{-}1h)$$

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Where:

ER = Default SO_2 emission rate for natural gas combustion, lb/mmBtu.

S_{total} = Total sulfur content of the natural gas, gr/100scf.

GCV = Gross calorific value of the natural gas, Btu/100scf.

7000 = Conversion of grains/100scf to lb/100scf.

2.0 = Ratio of lb SO_2/lb S.

10^6 = Conversion factor (Btu/mmBtu).

2.3.2.1.2 [Reserved]

2.3.2.2 Hourly Heat Input Rate

Calculate hourly heat input rate for natural gas combustion, in mmBtu/hr, using the procedures in section 3.4.1 of this appendix. Use the measured fuel flow rate from section 2.1 of this appendix and the gross calorific value from section 2.3.4.2 of this appendix in the calculations.

2.3.2.3 SO_2 Mass Emission Rate and Hourly Mass Emissions

For natural gas combustion, calculate the SO_2 mass emission rate, in lb/hr, using Equation D-5 in section 3.3.2 of this appendix, when the default SO_2 emission rate is used. Then, use the calculated SO_2 mass emission rate and the unit operating time to determine the hourly SO_2 mass emissions from natural gas combustion, in lb, using Equation D-12 in section 3.5.1 of this appendix.

2.3.2.4 Documentation that a Fuel Is Natural Gas

(a) A fuel may initially qualify as natural gas, if information is provided in the monitoring plan required under §75.53, demonstrating that the definition of natural gas in §72.2 of this chapter has been met. The information must demonstrate that the fuel meets either the percent methane or GCV requirement and has a total sulfur content of 20.0 grains/100 scf or less. This demonstration must be made using one of the following sources of information:

(1) The gas quality characteristics specified by a purchase contract, tariff sheet, or by a transportation contract; or

(2) Historical fuel sampling data for the previous 12 months, documenting the total sulfur content of the fuel and the GCV and/or percentage by volume of methane. The results of all sample analyses obtained by or provided to the owner or operator in the previous 12 months shall be used in the demonstration, and each sample result must meet the definition of natural gas in §72.2 of this chapter; or

(3) If the requirements of paragraphs (a)(1) and (a)(2) of this section cannot be met, a fuel may initially qualify as natural gas if at least one representative sample of the fuel is obtained and analyzed for total sulfur content and for either the gross calorific value (GCV) or percent methane, and the results of the sample analysis show that the fuel meets the definition of natural gas in §72.2 of this chapter. Use the sampling methods specified in sections 2.3.3.1.2 and 2.3.4 of this appendix. The required fuel sample may be obtained and analyzed by the owner or operator, by an independent laboratory, or by the fuel supplier. If multiple samples are taken, each sample must meet the definition of natural gas in §72.2 of this chapter.

(b) If the results of the fuel sampling under paragraph (a)(2) or (a)(3) of this section show that the fuel does not meet the definition of natural gas in §72.2 of this chapter, but those results are believed to be anomalous, the owner or operator may document the reasons for believing this in the monitoring plan for the unit, and may immediately perform additional sampling. In such cases, a minimum of three additional samples must be obtained and analyzed, and the results of each sample analysis must meet the definition of natural gas.

(c) If several affected units are supplied by a common source of gaseous fuel, a single sampling result may be applied to all of the units and it is not necessary to obtain a separate sample for each unit, provided that the composition of the fuel is not altered by blending or mixing it with other gaseous fuel(s) when it is transported from the sampling location to the affected units. For the purposes of this paragraph, the term “other gaseous fuel(s)” excludes compounds such as mercaptans when they are added in trace quantities for safety reasons.

(d) If the results of fuel sampling and analysis under paragraph (a)(2), (a)(3), or (b) of this section show that the fuel does not qualify as natural gas, the owner or operator shall re-classify the fuel as “other gaseous fuel” and shall implement the procedures of section 2.3.3 of this appendix, within 180 days of the end of the quarter in which the disqualifying sample was taken. In addition, the owner or operator shall use Equation D-1h in this appendix to calculate a default SO_2 emission rate for the fuel, based on the results of the sample analysis that exceeded 20 grains/100 scf of total sulfur, and shall use that default emission rate to report SO_2 mass emissions under this part until section 2.3.3 of this appendix has been fully implemented.

(e) If a fuel qualifies as natural gas based on the specifications in a fuel contract or tariff sheet, no additional, on-going sampling of the fuel's total sulfur content is required, provided that the contract or tariff sheet is current, valid and representative of the fuel combusted in the unit. If the fuel qualifies as natural gas based on fuel sampling and analysis, the owner or operator shall sample the fuel for total sulfur content at least annually and when the fuel supply source changes. For the purposes of this paragraph, (e), sampling “annually” means that at least one sample is taken in each calendar year. The effective date of the annual total sulfur sampling requirement is January 1, 2003.

(f) On-going sampling of the GCV of the natural gas is required under section 2.3.4.2 of this appendix.

(g) For units that are required to monitor and report NO_X mass emissions and heat input under subpart H of this part, but which are not affected units under the Acid Rain Program, the owner or operator is exempted from the requirements in paragraphs (a) and (e) of this section to document the total sulfur content of the natural gas.

2.3.3 SO_2 Mass Emissions From Any Gaseous Fuel

The owner or operator of a unit may determine SO_2 mass emissions using this section for any gaseous fuel (including fuels such as refinery gas, landfill gas, digester gas, coke oven gas, blast furnace gas, coal-derived gas, producer gas or any other gas which may have a variable sulfur content).

2.3.3.1 Sulfur Content Determination

2.3.3.1.1 Analyze the total sulfur content of the gaseous fuel in grains/100 scf, at the frequency specified in Table D-5 of this appendix. That is: for fuel delivered in discrete shipments or lots, sample each shipment or lot. For fuel transmitted by pipeline, sample hourly unless a demonstration is provided under section 2.3.6 of this appendix showing that the gaseous fuel qualifies for less frequent (*i.e.,* daily or annual) sampling. If daily sampling is required, determine the sulfur content using either manual sampling or a gas chromatograph. If hourly sampling is required, determine the sulfur content using a gas chromatograph. For units that are required to monitor and report NO_X mass emissions and heat input under subpart H of this part, but which are not affected units under the Acid Rain Program, the owner or operator is exempted from the requirements of this section to document the total sulfur content of the gaseous fuel.

2.3.3.1.2 Use one of the following methods when using manual sampling (as applicable to the type of gas combusted) to determine the sulfur content of the fuel: ASTM D1072-06, Standard Test Method for Total Sulfur in Fuel Gases by Combustion and Barium Chloride Titration, ASTM D4468-85 (Reapproved 2006), Standard Test Method for Total Sulfur in Gaseous Fuels by Hydrogenolysis and Rateometric Colorimetry, ASTM D5504-01, Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence, ASTM D6667-04, Standard Test Method for Determination of Total Volatile Sulfur in Gaseous Hydrocarbons and Liquefied Petroleum Gases by Ultraviolet Fluorescence, or ASTM D3246-96, Standard Test Method for Sulfur in Petroleum Gas by Oxidative Microcoulometry, (all incorporated by reference under §75.6 of this part). Alternatively, the gas samples may be analyzed for percent sulfur by any consensus standard method prescribed for the affected unit under part 60 of this chapter.

2.3.3.1.3 The sampling and analysis of daily manual samples may be performed by the owner or operator, an outside laboratory, or the gas supplier. If hourly sampling with a gas chromatograph is required, or a source chooses to use an online gas chromatograph to determine daily fuel sulfur content, the owner or operator shall develop and implement a program to quality assure the data from the gas chromatograph, in accordance with the manufacturer's recommended procedures. The quality assurance procedures shall be kept on-site, in a form suitable for inspection.

2.3.3.1.4 Results of all sample analyses must be available no later than thirty calendar days after the sample is taken.

2.3.3.2 SO_2 Mass Emission Rate

Calculate the SO_2 mass emission rate for the gaseous fuel, in lb/hr, using Equation D-4 or D-5 (as applicable) in section 3.3.1 of this appendix. Equation D-5 may only be used if a demonstration is performed under section 2.3.6 of this appendix, showing that the fuel qualifies to use a default SO_2 emission rate to account for SO_2 mass emissions under this part. Use the appropriate sulfur content or default SO_2 emission rate in Equation D-4 or D-5, as specified in Table D-5 of this appendix. If the fuel qualifies to use Equation D-5, the default SO_2 emission rate shall be calculated using Equation D-1h in section 2.3.2.1.1 of this appendix, replacing the words “natural gas” in the equation nomenclature with the words, “gaseous fuel”. In all cases, for reporting purposes, apply the results of the required periodic total sulfur samples in accordance with the provisions of section 2.3.7 of this appendix.

2.3.3.3 Hourly Heat Input Rate

Calculate the hourly heat input rate for combustion of the gaseous fuel, using the provisions in section 3.4.1 of this appendix. Use the measured fuel flow rate from section 2.1 of this appendix and the gross calorific value from section 2.3.4.3 of this appendix in the calculations.

2.3.4 Gross Calorific Values for Gaseous Fuels

Determine the GCV of each gaseous fuel at the frequency specified in this section, using one of the following methods: 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 (all incorporated by reference under §75.6 of this part). Use the appropriate GCV value, as specified in section 2.3.4.1, 2.3.4.2, or 2.3.4.3 of this appendix, in the calculation of unit hourly heat input rates. Alternatively, the gas samples may be analyzed for heat content by any consensus standard method prescribed for the affected unit under part 60 of this chapter.

2.3.4.1 GCV of Pipeline Natural Gas

Determine the GCV of fuel that is pipeline natural gas, as defined in §72.2 of this chapter, at least once per calendar month. For GCV used in calculations use the specifications in Table D-5: either the value from the most recent monthly sample, the highest value specified in a contract or tariff sheet, or the highest value from the previous year. The fuel GCV value from the most recent monthly sample shall be used for any month in which that value is higher than a contract limit. If a unit combusts pipeline natural gas for less than 48 hours during a calendar month, the sampling and analysis requirement for GCV is waived for that calendar month. The preceding waiver is limited by the condition that at least one analysis for GCV must be performed for each quarter the unit operates for any amount of time. If multiple GCV samples are taken and analyzed in a particular month, the GCV values from all samples shall be averaged arithmetically to obtain the monthly GCV. Then, apply the monthly average GCV value as described in paragraph (c) in section 2.3.7 of this appendix.

2.3.4.2 GCV of Natural Gas

Determine the GCV of fuel that is natural gas, as defined in §72.2 of this chapter, on a monthly basis, in the same manner as described for pipeline natural gas in section 2.3.4.1 of this appendix.

2.3.4.3 GCV of Other Gaseous Fuels

For gaseous fuels other than natural gas or pipeline natural gas, determine the GCV as specified in section 2.3.4.3.1, 2.3.4.3.2 or 2.3.4.3.3, as applicable. For reporting purposes, apply the results of the required periodic GCV samples in accordance with the provisions of section 2.3.7 of this appendix.

2.3.4.3.1 For a gaseous fuel that is delivered in discrete shipments or lots, determine the GCV for each shipment or lot. The determination may be made by sampling each delivery or by sampling the supply tank after each delivery. For sampling of each delivery, use the highest GCV in the previous year's samples. For sampling from the tank after each delivery, use either the most recent GCV sample, the maximum GCV specified in the fuel contract or tariff sheet, or the highest GCV from the previous year's samples.

2.3.4.3.2 For any gaseous fuel that does not qualify as pipeline natural gas or natural gas, which is not delivered in shipments or lots, and for which the owner or operator performs the 720 hour test under section 2.3.5 of this appendix, if the results of the test demonstrate that the gaseous fuel has a low GCV variability, determine the GCV at least monthly (as described in section 2.3.4.1 of this appendix). In calculations of hourly heat input for a unit, use either the most recent monthly sample, the maximum GCV specified in the fuel contract or tariff sheet, or the highest fuel GCV from the previous year's samples.

2.3.4.3.3 For any other gaseous fuel, determine the GCV at least daily and use the actual fuel GCV in calculations of unit hourly heat input. If an online gas chromatograph or on-line calorimeter is used to determine fuel GCV each day, the owner or operator shall develop and implement a program to quality assure the data from the gas chromatograph or on-line calorimeter, in accordance with the manufacturer's recommended procedures. The quality assurance procedures shall be kept on-site, in a form suitable for inspection.

2.3.5 Demonstration of Fuel GCV Variability

(a) This optional demonstration may be made for any fuel which does not qualify as pipeline natural gas or natural gas, and is not delivered only in shipments or lots. The demonstration data may be used to show that monthly sampling of the GCV of the gaseous fuel or blend is sufficient, in lieu of daily GCV sampling.

(b) To make this demonstration, proceed as follows. Provide a minimum of 720 hours of data, indicating the GCV of the gaseous fuel or blend (in Btu/100 scf). The demonstration data shall be obtained using either: hourly sampling and analysis using the methods in section 2.3.4 to determine GCV of the fuel; an on-line gas chromatograph capable of determining fuel GCV on an hourly basis; or an on-line calorimeter. For gaseous fuel produced by a variable process, the data shall be representative of and include all process operating conditions including seasonal and yearly variations in process which may affect fuel GCV.

(c) The data shall be reduced to hourly averages. The mean GCV value and the standard deviation from the mean shall be calculated from the hourly averages. Specifically, the gaseous fuel is considered to have a low GCV variability, and monthly gas sampling for GCV may be used, if the mean value of the GCV multiplied by 1.075 is greater than the sum of the mean value and one standard deviation. If the gaseous fuel or blend does not meet this requirement, then daily fuel sampling and analysis for GCV, using manual sampling, a gas chromatograph or an on-line calorimeter is required.

2.3.6 Demonstration of Fuel Sulfur Variability

(a) This demonstration may be made for any fuel which does not qualify as pipeline natural gas or natural gas, and is not delivered only in shipments or lots. The results of the demonstration may be used to show that daily sampling for sulfur in the fuel is sufficient, rather than hourly sampling. The procedures in this section may also be used to demonstrate that a particular gaseous fuel qualifies to use a default SO_2 emission rate (calculated using Equation D-1h in section 2.3.2.1.1 of this appendix) for the purpose of reporting hourly SO_2 mass emissions under this part. To make this demonstration, proceed as follows. Provide a minimum of 720 hours of data, indicating the total sulfur content of the gaseous fuel (in gr/100 scf). The demonstration data shall be obtained using either manual hourly sampling or an on-line gas chromatograph (GC) capable of determining fuel total sulfur content on an hourly basis. For gaseous fuel produced by a variable process, the data shall be representative of all process operating conditions including seasonal or annual variations which may affect fuel sulfur content.

(b) If the data are collected with an on-line GC, reduce the data to hourly average values of the total sulfur content of the fuel. If manual hourly sampling is used, the results of each hourly sample analysis shall be the total sulfur value for that hour. Express all hourly average values of total sulfur content in units of grains/100 scf. Use all of the hourly average values of total sulfur content in grains/100 scf to calculate the mean value and the standard deviation. Also determine the 90th percentile and maximum hourly values of the total sulfur content for the data set. If the standard deviation of the hourly values from the mean does not exceed 5.0 grains/100 scf, the fuel has a low sulfur variability. If the standard deviation exceeds 5.0 grains/100 scf, the fuel has a high sulfur variability. Based on the results of this determination, establish the required sampling frequency and SO_2 mass emissions methodology for the gaseous fuel, as follows:

(1) If the gaseous fuel has a low sulfur variability (irrespective of the total sulfur content), the owner or operator may either perform daily sampling of the fuel's total sulfur content using manual sampling or a GC, or may report hourly SO_2 mass emissions data using a default SO_2 emission rate calculated by substituting the 90th percentile value of the total sulfur content in Equation D-1h.

(2) If the gaseous fuel has a high sulfur variability, but the maximum hourly value of the total sulfur content does not exceed 20 grains/100 scf, the owner or operator may either perform hourly sampling of the fuel's total sulfur content using an on-line GC, or may report hourly SO_2 mass emissions data using a default SO_2 emission rate calculated by substituting the maximum value of the total sulfur content in Equation D-1h.

(3) If the gaseous fuel has a high sulfur variability and the maximum hourly value of the total sulfur content exceeds 20 grains/100 scf, the owner or operator shall perform hourly sampling of the fuel's total sulfur content, using an on-line GC.

(4) Any gaseous fuel under paragraph (b)(1) or (b)(2) of this section, for which the owner or operator elects to use a default SO_2 emission rate for reporting purposes is subject to the annual total sulfur sampling requirement under section 2.3.2.4(e) of this appendix.

2.3.7 Application of Fuel Sampling Results

For reporting purposes, apply the results of the required periodic fuel samples described in Tables D-4 and D-5 of this appendix as follows. Use Equation D-1h to recalculate the SO_2 emission rate, as necessary.

(a) For daily samples of total sulfur content or GCV:

(1) If the actual value is to be used in the calculations, apply the results of each daily sample to all hours in the day on which the sample is taken; or

(2) If the highest value in the previous 30 daily samples is to be used in the calculations, apply that value to all hours in the current day. If, for a particular unit, fewer than 30 daily samples have been collected, use the highest value from all available samples until 30 days of historical sampling results have been obtained.

(b) For annual samples of total sulfur content:

(1) For pipeline natural gas, use the results of annual sample analyses in the calculations only if the results exceed 0.5 grains/100 scf. In that case, if the fuel still qualifies as natural gas, follow the procedures in paragraph (b)(2) of this section. If the fuel does not qualify as natural gas, the owner or operator shall implement the procedures in section 2.3.3 of this appendix, in the time frame specified in sections 2.3.1.4(d) and 2.3.2.4(d) of this appendix;

(2) For natural gas, if only one sample is taken, apply the results beginning at the date on which the sample was taken. If multiple samples are taken and averaged, apply the results beginning at the date on which the last sample used in the annual assessment was taken;

(3) For other gaseous fuels with an annual sampling requirement under section 2.3.6(b)(4) of this appendix, use the sample results in the calculations only if the results exceed the 90th percentile value or maximum value (as applicable) from the 720-hour demonstration of fuel sulfur content and variability under section 2.3.6 of this appendix.

(c) For monthly samples of the fuel GCV:

(1) If the actual monthly value is to be used in the calculations and only one sample is taken, apply the results starting from the date on which the sample was taken. If multiple samples are taken and averaged, apply the monthly average GCV value to the entire month; or

(2) If an assumed value (contract maximum or highest value from previous year's samples) is to be used in the calculations, apply the assumed value to all hours in each month of the quarter unless a higher value is obtained in a monthly GCV sample (or, if multiple samples are taken and averaged, if the monthly average exceeds the assumed value). In that case, if only one monthly sample is taken, use the sampled value, starting from the date on which the sample was taken. If multiple samples are taken and averaged, use the average value for the entire month in which the assumed value was exceeded. Consider the sample (or, if applicable, monthly average) results to be the new assumed value. Continue using the new assumed value unless and until one of the following occurs (as applicable to the reporting option selected): The assumed value is superseded by a higher value from a subsequent monthly sample (or by a higher monthly average); or the assumed value is superseded by a new contract in which case the new contract value becomes the assumed value at the time the fuel specified under the new contract begins to be combusted in the unit; or both the calendar year in which the new sampled value (or monthly average) exceeded the assumed value and the subsequent calendar year have elapsed.

(d) For samples of gaseous fuel delivered in shipments or lots:

(1) If the actual value for the most recent shipment is to be used in the calculations, apply the results of the most recent sample, from the date on which the sample was taken until the date on which the next sample is taken; or

(2) If an assumed value (contract maximum or highest value from previous year's samples) is to be used in the calculations, apply the assumed value unless a higher value is obtained in a sample of a shipment. In that case, use the sampled value, starting from the date on which the sample was taken. Consider the sample results to be the new assumed value. Continue using the new assumed value unless and until: it is superseded by a higher value from a sample of a subsequent shipment; or (if applicable) it is superseded by a new contract in which case the new contract value becomes the assumed value at the time the fuel specified under the new contract begins to be combusted in the unit; or (if applicable) both the calendar year in which the sampled value exceeded the assumed value and the subsequent calendar year have elapsed.

(e) When the owner or operator elects to use assumed values in the calculations, the results of periodic samples of sulfur content and GCV which show that the assumed value has not been exceeded need not be reported. Keep these sample results on file, in a format suitable for inspection.

(f) Notwithstanding the requirements of paragraphs (b) through (d) of this section, in cases where the sample results are provided to the owner or operator by the supplier of the fuel, the owner or operator shall begin using the sampling results on the date of receipt of those results, rather than on the date that the sample was taken.

2.4 Missing Data Procedures.

When data from the procedures of this part are not available, provide substitute data using the following procedures.

2.4.1 Missing Data for Oil and Gas Samples

When fuel sulfur content, gross calorific value or, when necessary, density data are missing or invalid for an oil or gas sample taken according to the procedures in section 2.2.3, 2.2.4.1, 2.2.4.2, 2.2.4.3, 2.2.5, 2.2.6, 2.2.7, 2.3.3.1.2, or 2.3.4 of this appendix, then substitute the maximum potential sulfur content, density, or gross calorific value of that fuel from Table D-6 of this appendix. Except for the annual samples of fuel sulfur content required under sections 2.3.1.4(e), 2.3.2.4(e) and 2.3.6(b)(5) of this appendix, the missing data values in Table D-6 shall be reported whenever the results of a required sample of sulfur content, GCV or density is missing or invalid in the current calendar year, irrespective of which reporting option is selected (i.e., actual value, contract value or highest value from the previous year). For the annual samples of fuel sulfur content required under sections 2.3.1.4(e), 2.3.2.4(e) and 2.3.6(b)(5) of this appendix, if a valid annual sample has not been obtained by the end of a particular calendar year, the appropriate missing data value in Table D-6 shall be reported, beginning with the first unit operating hour in the next calendar year. The substitute data value(s) shall be used until the next valid sample for the missing parameter(s) is obtained. Note that only actual sample results shall be used to determine the “highest value from the previous year” when that reporting option is used; missing data values shall not be used in the determination.

TABLE D-6. -- MISSING DATA SUBSTITUTION PROCEDURES FOR SULFUR, DENSITY, AND GROSS CALORIFIC VALUE DATA

Parameter	Missing data substitution maximum potential value
Oil Sulfur Content	3.5 percent for residual oil, or 1.0 percent for diesel fuel.
Oil Density	8.5 lb/gal for residual oil, or 7.4 lb/gal for diesel fuel.
Oil GCV	19,500 Btu/lb for residual oil, or 20,000 Btu/lb for diesel fuel.
Gas Total Sulfur Content	1. For pipeline natural gas, where annual sampling is required, substitute 0.002 lb/mmBtu for each hour of the missing data period. 2. For natural gas (or other gaseous fuel that qualifies to use a default SO_2 emission rate under section 2.3.6 of this appendix), where annual sampling is required, substitute 1.5 times the default SO_2 emission rate in use at the time of the missing data period. 3. For any gaseous fuel sampled daily, 1.5 times the highest total sulfur content value from the previous 30 days on which valid samples were obtained. 4. For any gaseous fuel sampled hourly, the highest total sulfur content value from the previous 720 hourly samples.
Gas GCV/Heat Content	110,000 Btu/100 scf for pipeline natural gas, natural gas or landfill gas. 150,000 Btu/100 scf for butane or refinery gas. 210,000 Btu/100 scf for propane or any other gaseous fuel.

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2.4.2 Missing Data Procedures for Fuel Flow Rate

Whenever data are missing from any primary fuel flowmeter system (as defined in §72.2 of this chapter) and there is no backup system available to record the fuel flow rate, use the procedures in sections 2.4.2.2 and 2.4.2.3 of this appendix to account for the flow rate of fuel combusted at the unit for each hour during the missing data period. Alternatively, for a fuel flowmeter system used to measure the fuel combusted by a peaking unit, the simplified fuel flow missing data procedure in section 2.4.2.1 of this appendix may be used. Before using the procedures in sections 2.4.2.2 and 2.4.2.3 of this appendix, establish load ranges for the unit using the procedures of section 2 in appendix C to this part, except for units that do not produce electrical output (i.e., megawatts) or thermal output (e.g., klb of steam per hour). The owner or operator of a unit that does not produce electrical or thermal output shall either perform missing data substitution without segregating the fuel flow rate data into bins, or may petition the Administrator under §75.66 for permission to segregate the data into operational bins. When load ranges are used for fuel flow rate missing data purposes, separate, fuel-specific databases shall be created and maintained. A database shall be kept for each type of fuel combusted in the unit, for the hours in which the fuel is combusted alone in the unit. An additional database shall be kept for each type of fuel, for the hours in which it is co-fired with any other type(s) of fuel(s).

2.4.2.1 Simplified Fuel Flow Rate Missing Data Procedure for Peaking Units

If no fuel flow rate data are available for a fuel flowmeter system installed on a peaking unit (as defined in §72.2 of this chapter), then substitute for each hour of missing data using the maximum potential fuel flow rate. The maximum potential fuel flow rate is the lesser of the following:

(a) The maximum fuel flow rate the unit is capable of combusting or

(b) The maximum flow rate that the fuel flowmeter can measure (i.e., the upper range value of the flowmeter).

2.4.2.2 Standard Missing Data Procedures—Single Fuel Hours

For missing data periods that occur when only one type of fuel is being combusted, provide substitute data for each hour in the missing data period as follows.

2.4.2.2.1 If load-based missing data procedures are used, substitute the arithmetic average of the hourly fuel flow rate(s) measured and recorded by a certified fuel flowmeter system at the corresponding operating unit load range during the previous 720 operating hours in which the unit combusted only that same fuel. If no fuel flow rate data are available at the corresponding load range, use data from the next higher load range, if such data are available. If no quality-assured fuel flow rate data are available at either the corresponding load range or a higher load range, substitute the maximum potential fuel flow rate (as defined in section 2.4.2.1 of this appendix) for each hour of the missing data period.

2.4.2.2.2 For units that do not produce electrical or thermal output and therefore cannot use load-based missing data procedures, provide substitute data for each hour of the missing data period as follows. Substitute the arithmetic average of the hourly fuel flow rates measured and recorded by a certified fuel flowmeter system during the previous 720 operating hours in which the unit combusted only that same fuel. If no quality-assured fuel flow rate data are available, substitute the maximum potential fuel flow rate (as defined in section 2.4.2.1 of this appendix) for each hour of the missing data period.

2.4.2.3 Standard Missing Data Procedures—Multiple Fuel Hours

For missing data periods that occur when two or more different types of fuel are being co-fired, provide substitute fuel flow rate data for each hour of the missing data period as follows.

2.4.2.3.1 If load-based missing data procedures are used, substitute the maximum hourly fuel flow rate measured and recorded by a certified fuel flowmeter system at the corresponding load range during the previous 720 operating hours when the fuel for which the flow rate data are missing was co-fired with any other type of fuel. If no such quality-assured fuel flow rate data are available at the corresponding load range, use data from the next higher load range (if available). If no quality-assured fuel flow rate data are available for co-fired hours, either at the corresponding load range or a higher load range, substitute the maximum potential fuel flow rate (as defined in section 2.4.2.1 of this appendix) for each hour of the missing data period.

2.4.2.3.2 For units that do not produce electrical or thermal output and therefore cannot use load-based missing data procedures, provide substitute fuel flow rate data for each hour of the missing data period as follows. Substitute the maximum hourly fuel flow rate measured and recorded by a certified fuel flowmeter system during the previous 720 operating hours in which the fuel for which the flow rate data are missing was co-fired with any other type of fuel. If no quality-assured fuel flow rate data for co-fired hours are available, substitute the maximum potential fuel flow rate (as defined in section 2.4.2.1 of this appendix) for each hour of the missing data period.

2.4.2.3.3 If, during an hour in which different types of fuel are co-fired, quality-assured fuel flow rate data are missing for two or more of the fuels being combusted, apply the procedures in section 2.4.2.3.1 or 2.4.2.3.2 of this appendix (as applicable) separately for each type of fuel.

2.4.2.3.4 If the missing data substitution required in section 2.4.2.3.1 or 2.4.2.3.2 causes the reported hourly heat input rate based on the combined fuel usage to exceed the maximum rated hourly heat input of the unit, adjust the substitute fuel flow rate value(s) so that the reported heat input rate equals the unit's maximum rated hourly heat input. Manual entry of the adjusted substitute data values is permitted.

2.4.3. In any case where the missing data provisions of this section require substitution of data measured and recorded more than three years (26,280 clock hours) prior to the date and time of the missing data period, use three years (26,280 clock hours) in place of the prescribed lookback period. In addition, for a new or newly-affected unit, until 720 hours of quality-assured fuel flowmeter data are available for the lookback periods described in sections 2.4.2.2 and 2.4.2.3 of this appendix, use all of the available fuel flowmeter data to determine the appropriate substitute data values.

3. Calculations

Calculate hourly SO_2 mass emission rate from combustion of oil fuel using the procedures in section 3.1 of this appendix. Calculate hourly SO_2 mass emission rate from combustion of gaseous fuel using the procedures in section 3.3 of this appendix. (Note: the SO_2 mass emission rates in sections 3.1 and 3.3 are calculated such that the rate, when multiplied by unit operating time, yields the hourly SO_2 mass emissions for a particular fuel for the unit.) Calculate hourly heat input rate for both oil and gaseous fuels using the procedures in section 3.4 of this appendix. Calculate total SO_2 mass emissions and heat input for each hour, each quarter and the year to date using the procedures under section 3.5 of this appendix. Where an oil flowmeter records volumetric flow rate, use the calculation procedures in section 3.2 of this appendix to calculate the mass flow rate of oil.

3.1 SO_2 Mass Emission Rate Calculation for Oil

3.1.1 Use Equation D-2 to calculate SO_2 mass emission rate per hour (lb/hr):

$$SO2_{rate\text{-}oil} = 2.0 \times OIL_{rate} \times \frac{\%S_{oil}}{100.0} \qquad (Eq.\ D\text{-}2)$$

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Where:

$SO_{2rate\text{-}oil}$ = Hourly mass emission rate of SO_2 emitted from combustion of oil, lb/hr.

OIL_{rate} = Mass rate of oil consumed per hr during combustion, lb/hr.

$\%S_{oil}$ = Percentage of sulfur by weight in the oil.

2.0 = Ratio of lb SO_2/lb S.

3.1.2 Record the SO_2 mass emission rate from oil for each hour that oil is combusted.

3.2 Mass Flow Rate Calculation for Volumetric Oil Flowmeters

3.2.1 Where the oil flowmeter records volumetric flow rate rather than mass flow rate, calculate and record the oil mass flow rate for each hourly period using hourly oil flow rate measurements and the density or specific gravity of the oil sample.

3.2.2 Convert density, specific gravity, or API gravity of the oil sample to density of the oil sample at the sampling location's temperature using ASTM D1250-07, Standard Guide for Use of the Petroleum Measurement Tables (incorporated by reference under (§75.6 of this part).

3.2.3 Where density of the oil is determined by the applicable ASTM procedures from section 2.2.6 of this appendix, use Equation D-3 to calculate the rate of the mass of oil consumed (in lb/hr):

$$OIL_{rate} = V_{oil\text{-}rate} \times D_{oil} \qquad (Eq.\ D\text{-}3)$$

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Where:

OIL_{rate} = Mass rate of oil consumed per hr, lb/hr.

$V_{oil\text{-}rate}$ = Volume rate of oil consumed per hr, measured in scf/hr, gal/hr, barrels/hr, or m^3/hr.

D_{oil} = Density of oil, measured in lb/scf, lb/gal, lb/barrel, or lb/m^3.

3.3 SO_2 Mass Emission Rate Calculation for Gaseous Fuels

3.3.1 Use Equation D-4 to calculate the SO_2 mass emission rate when using the optional gas sampling and analysis procedures in sections 2.3.1 and 2.3.2 of this appendix, or the required gas sampling and analysis procedures in section 2.3.3 of this appendix. Total sulfur content of a fuel must be determined using the procedures of 2.3.3.1.2 of this appendix:

$$SO_{2_{rate\text{-}gas}} = \left(\frac{2.0}{7000}\right) \times GAS_{rate} \times S_{gas} \qquad (Eq.\ D\text{-}4)$$

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Where:

SO2rate-gas = Hourly mass rate of SO_2 emitted due to combustion of gaseous fuel, lb/hr.

GASrate = Hourly metered flow rate of gaseous fuel combusted, 100 scf/hr.

Sgas = Sulfur content of gaseous fuel, in grain/100 scf.

2.0 = Ratio of lb SO_2/lb S.

7000 = Conversion of grains/100 scf to lb/100 scf.

3.3.2 Use Equation D-5 to calculate the SO_2 mass emission rate when using a default emission rate from section 2.3.1.1 or 2.3.2.1.1 of this appendix:

$$SO2_{rate} = ER \times HI_{rate} \qquad (Eq.\ D\text{-}5)$$

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where:

SO_2rate = Hourly mass emission rate of SO_2 from combustion of a gaseous fuel, lb/hr.

ER = SO_2 emission rate from section 2.3.1.1 or 2.3.2.1.1, of this appendix, lb/mmBtu.

HI_{rate} = Hourly heat input rate of a gaseous fuel, calculated using procedures in section 3.4.1 of this appendix, in mmBtu/hr.

3.3.3 Record the SO_2 mass emission rate for each hour when the unit combusts a gaseous fuel.

3.4 Calculation of Heat Input Rate

3.4.1 Heat Input Rate for Gaseous Fuels

(a) Determine total hourly gas flow or average hourly gas flow rate with a fuel flowmeter in accordance with the requirements of section 2.1 of this appendix and the fuel GCV in accordance with the requirements of section 2.3.4 of this appendix. If necessary perform the 720-hour test under section 2.3.5 to determine the appropriate fuel GCV sampling frequency.

(b) Then, use Equation D-6 to calculate heat input rate from gaseous fuels for each hour.

$$HI_{rate\text{-}gas} = \frac{GAS_{rate} \times GCV_{gas}}{10^6} \qquad (Eq.\ \text{D-6})$$

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Where:

$HI_{rate\text{-}gas}$ = Hourly heat input rate from combustion of the gaseous fuel, mmBtu/hr.

GAS_{rate} = Average volumetric flow rate of fuel, for the portion of the hour in which the unit operated, 100 scf/hr.

GCV_{gas} = Gross calorific value of gaseous fuel, Btu/100 scf.

10^6 = Conversion of Btu to mmBtu.

(c) Note that when fuel flow is measured on an hourly totalized basis (e.g. a fuel flowmeter reports totalized fuel flow for each hour), before Equation D-6 can be used, the total hourly fuel usage must be converted from units of 100 scf to units of 100 scf/hr using Equation D-7:

$$GAS_{rate} = \frac{GAS_{unit}}{t} \qquad (Eq.\ \text{D-7})$$

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Where:

GAS_{rate} = Average volumetric flow rate of fuel for the portion of the hour in which the unit operated, 100 scf/hr.

GAS_{unit} = Total fuel combusted during the hour, 100 scf.

t = 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).

3.4.2 Heat Input Rate From the Combustion of Oil

(a) Determine total hourly oil flow or average hourly oil flow rate with a fuel flowmeter, in accordance with the requirements of section 2.1 of this appendix. Determine oil GCV according to the requirements of section 2.2 of this appendix.

Then, use Equation D-8 to calculate hourly heat input rate from oil for each hour:

$$HI_{rate\text{-}oil} = OIL_{rate} \frac{GCV_{oil}}{10^6} \qquad (Eq.\ \text{D-8})$$

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Where:

$HI_{rate\text{-}oil}$ = Hourly heat input rate from combustion of oil, mmBtu/hr.

OIL_{rate} = Mass rate of oil consumed per hour, as determined using procedures in section 3.2.3 of this appendix, in lb/hr, tons/hr, or kg/hr.

GCV_{oil} = Gross calorific value of oil, Btu/lb, Btu/ton, or Btu/kg.

10^6 = Conversion of Btu to mmBtu.

(b) Note that when fuel flow is measured on an hourly totalized basis (e.g., a fuel flowmeter reports totalized fuel flow for each hour), before equation D-8 can be used, the total hourly fuel usage must be converted from units of lb to units of lb/hr, using equation D-9:

$$OIL_{rate} = \frac{OIL_{unit}}{t} \qquad (Eq.\ D\text{-}9)$$

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Where:

OIL_{rate} = Average fuel flow rate for the portion of the hour which the unit operated in lb/hr.

OIL_{unit} = Total fuel combusted during the hour, lb.

t = 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).

(c) For affected units that are not subject to an Acid Rain emissions limitation, but are regulated under a State or federal NO_X mass emissions reduction program that adopts the requirements of subpart H of this part, the following alternative method may be used to determine the heat input rate from oil combustion, when the oil flowmeter measures the flow rate of oil volumetrically. In lieu of measuring the oil density and converting the volumetric oil flow rate to a mass flow rate, Equation D-8 may be applied on a volumetric basis. If this option is selected, express the terms OIL_{rate} and GCV_{oil} in Equation D-8 in units of volume rather than mass. For example, the units of OIL_{rate} may be gal/hr and the units of GCV_{oil} may be Btu/gal.

3.4.3 Apportioning Heat Input Rate to Multiple Units

(a) Use the procedure in this section to apportion hourly heat input rate to two or more units using a single fuel flowmeter which supplies fuel to the units. The designated representative may also petition the Administrator under §75.66 to use this apportionment procedure to calculate SO_2 and CO_2 mass emissions.

(b) Determine total hourly fuel flow or flow rate through the fuel flowmeter supplying gas or oil fuel to the units. Convert fuel flow rates to units of 100 scf for gaseous fuels or to lb for oil, using the procedures of this appendix. Apportion the fuel to each unit separately based on hourly output of the unit in MW_e or 1000 lb of steam/hr (klb/hr) using Equation F-21a or F-21b in appendix F to this part, as applicable:

Equation D-10 [Reserved]

Equation D-11 [Reserved]

(c) Use the total apportioned fuel flow calculated from Equation F-21a or F-21b to calculate the hourly unit heat input rate, using Equations D-6 and D-7 (for gas) or Equations D-8 and D-9 (for oil).

3.5 Conversion of Hourly Rates to Hourly, Quarterly, and Year-to-Date Totals

3.5.1 Hourly SO_2 Mass Emissions from the Combustion of all Fuels. Determine the total mass emissions for each hour from the combustion of all fuels using Equation D-12 (On and after January 1, 2009, determine the total mass emission rate (in lbs/hr) for each hour from the combustion of all fuels by dividing Equation D-12 by the actual unit operating time for the hour):

$$M_{SO2-hr} = \sum_{all-fuels} SO2_{rate-i}\, t_i \qquad (Eq.\ D\text{-}12)$$

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Where:

MSO_2-hr = Total mass of SO_2 emissions from all fuels combusted during the hour, lb.

SO_2 rate−I = SO_2 mass emission rate for each type of gas or oil fuel combusted during the hour, lb/hr.

ti = Time each gas or oil fuel was combusted for the hour (fuel usage time), 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).

3.5.2 Quarterly Total SO_2 Mass Emissions

Sum the hourly SO_2 mass emissions in lb as determined from Equation D-12 for all hours in a quarter using Equation D-13:

$$M_{SO2\text{-}qtr} = \frac{1}{2000} \sum_{all\text{-}hours\text{-}in\text{-}qtr} M_{SO2\text{-}hr} \qquad (Eq.\ \text{D-13})$$

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Where:

$M_{SO2\text{-}qtr}$ = Total mass of SO_2 emissions from all fuels combusted during the quarter, tons.

$M_{SO2\text{-}hr}$ = Hourly SO_2 mass emissions determined using Equation D-12, lb.

2000= Conversion factor from lb to tons.

3.5.3 Year to Date SO_2 Mass Emissions

Calculate and record SO_2 mass emissions in the year to date using Equation D-14:

$$M_{SO2\text{-}YTD} = \sum_{q=1}^{current\text{-}quarter} \mathrm{M}_{SO2\text{-}qtr} \qquad (Eq.\ \text{D-14})$$

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Where:

$M_{SO2\text{-}YTD}$ = Total SO_2 mass emissions for the year to date, tons.

$M_{SO2\text{-}qtr}$ = Total SO_2 mass emissions for the quarter, tons.

3.5.4 Hourly Total Heat Input Rate and Heat Input from the Combustion of all Fuels

3.5.4.1 Determine the total heat input in mmBtu for each hour from the combustion of all fuels using Equation D-15:

$$HI_{hr} = \sum_{all\text{-}fuels} HI_{rate\text{-}i} t_i \qquad (Eq.\ \text{D-15})$$

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Where:

HI_{hr} = Total heat input from all fuels combusted during the hour, mmBtu.

$HI_{rate\text{-}i}$ = Heat input rate for each type of gas or oil combusted during the hour, mmBtu/hr.

t_i = Time each gas or oil fuel was combusted for the hour (fuel usage time), 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).

3.5.4.2 For reporting purposes, determine the heat input rate to each unit, in mmBtu/hr, for each hour from the combustion of all fuels using Equation D-15a:

$$HI_{rate\text{-}hr} = \frac{\sum_{all\text{-}fuels} \mathrm{HI}_{rate\text{-}i} t_i}{\mathrm{t}_u} \qquad (Eq.\ \text{D-15}a)$$

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Where:

$HI_{rate\text{-}hr}$ = Total heat input rate from all fuels combusted during the hour, mmBtu/hr.

$HI_{rate\text{-}i}$ = Heat input rate for each type of gas or oil combusted during the hour, mmBtu/hr.

t_i = Time each gas or oil fuel was combusted for the hour (fuel usage time), 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_u = Unit operating time

3.5.5 Quarterly Heat Input

Sum the hourly heat input values determined from equation D-15 for all hours in a quarter using Equation D-16:

$$HI_{qtr} = \sum_{all\text{-}hours\text{-}in\text{-}qtr} \mathrm{HI}_{hr} \qquad (Eq.\ \mathrm{D}\text{-}16)$$

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Where:

HIqtr = Total heat input from all fuels combusted during the quarter, mmBtu.

HIqtr = Hourly heat input determined using Equation D-15, mmBtu.

3.5.6 Year-to-Date Heat Input

Calculate and record the total heat input in the year to date using Equation D-17.

$$HI_{YTD} = \sum_{q=1}^{current\text{-}quarter} \mathrm{HI}_{qtr} \qquad (Eq.\ \mathrm{D}\text{-}17)$$

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HI_{YTD} = Total heat input for the year to date, mmBtu.

HI_{qtr} = Total heat input for the quarter, mmBtu.

3.6 Records and Reports

Calculate and record quarterly and cumulative SO_2 mass emissions and heat input for each calendar quarter using the procedures and equations of section 3.5 of this appendix. Calculate and record SO_2 emissions and heat input data using a data acquisition and handling system. Report these data in a standard electronic format specified by the Administrator.

[58 FR 3701, Jan. 11, 1993, as amended at 60 FR 26548, 26551, May 17, 1995; 61 FR 25585, May 22, 1996; 61 FR 59166, Nov. 20, 1996; 63 FR 57513, Oct. 27, 1998; 64 FR 28652, May 26, 1999; 64 FR 37582, July 12, 1999; 67 FR 40460, 40472, June 12, 2002; 67 FR 53505, Aug. 16, 2002; 73 FR 4369, Jan. 24, 2008; 76 FR 17324, Mar. 28, 2011; 76 FR 20536, Apr. 13, 2011; 77 FR 2460, Jan. 18, 2012]

Editorial Note: At 67 FR 53505, Aug. 16, 2002, section 2.4.1 Table D-6 was amended. However, this table is a photographed graphic and the amendments could not be incorporated.

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Appendix E to Part 75—Optional NO_X Emissions Estimation Protocol for Gas-Fired Peaking Units and Oil-Fired Peaking Units

1. Applicability

1.1 Unit Operation Requirements

This NO_X emissions estimation procedure may be used in lieu of a continuous NO_X emission monitoring system (lb/mmBtu) for determining the average NO_X emission rate and hourly NO_X rate from gas-fired peaking units and oil-fired peaking units as defined in §72.2 of this chapter. If a unit's operations exceed the levels required to be a peaking unit, the owner or operator shall install and certify a NO_X-diluent continuous emission monitoring system no later than December 31 of the following calendar year. If the required CEMS has not been installed and certified by that date, the owner or operator shall report the maximum potential NO_X emission rate (MER) (as defined in §72.2 of this chapter) for each unit operating hour, starting with the first unit operating hour after the deadline and continuing until the CEMS has been provisionally certified. The provision of §75.12 apply to excepted monitoring systems under this appendix.

1.2 Certification

1.2.1 Pursuant to the procedures in §75.20, complete all testing requirements to certify use of this protocol in lieu of a NO_X continuous emission monitoring system no later than the applicable deadline specified in §75.4. Apply to the Administrator for certification to use this method no later than 45 days after the completion of all certification testing. Whenever the monitoring method is to be changed, reapply to the Administrator for certification of the new monitoring method.

1.2.2 [Reserved]

2. Procedure

2.1 Initial Performance Testing

Use the following procedures for: measuring NO_X emission rates at heat input rate levels corresponding to different load levels; measuring heat input rate; and plotting the correlation between heat input rate and NO_X emission rate, in order to determine the emission rate of the unit(s). The requirements in section 6.1.2 of appendix A to this part shall apply to any stack testing performed to obtain O_2 and NO_X concentration measurements under this appendix, either for units using the excepted methodology in this appendix or for units using the low mass emissions excepted methodology in §75.19.

2.1.1 Load Selection

Establish at least four approximately equally spaced operating load points, ranging from the maximum operating load to the minimum operating load. Select the maximum and minimum operating load from the operating history of the unit during the most recent two years. (If projections indicate that the unit's maximum or minimum operating load during the next five years will be significantly different from the most recent two years, select the maximum and minimum operating load based on the projected dispatched load of the unit.) For new gas-fired peaking units or new oil-fired peaking units, select the maximum and minimum operating load from the expected maximum and minimum load to be dispatched to the unit in the first five calendar years of operation.

2.1.2 NO_X and O_2 Concentration Measurements

Use the following procedures to measure NO_X and O_2 concentration in order to determine NO_X emission rate.

2.1.2.1 For boilers, select an excess O_2 level for each fuel (and, optionally, for each combination of fuels) to be combusted that is representative for each of the four or more load levels. If a boiler operates using a single, consistent combination of fuels only, the testing may be performed using the combination rather than each fuel. If a fuel is combusted only for the purpose of testing ignition of the burners for a period of five minutes or less per ignition test or for start-up, then the boiler NO_X emission rate does not need to be tested separately for that fuel. Operate the boiler at a normal or conservatively high excess oxygen level in conjunction with these tests. Measure the NO_X and O_2 at each load point for each fuel or consistent fuel combination (and, optionally, for each combination of fuels) to be combusted. Measure the NO_X and O_2 concentrations according to method 7E and 3A in appendix A of part 60 of this chapter. Use a minimum of 12 sample points, located according to Method 1 in appendix A-1 to part 60 of this chapter. The designated representative for the unit may also petition the Administrator under §75.66 to use fewer sampling points. Such a petition shall include the proposed alternative sampling procedure and information demonstrating that there is no concentration stratification at the sampling location.

2.1.2.2 For stationary gas turbines, sample at a minimum of 12 points per run at each load level. Locate the sample points according to Method 1 in appendix A-1 to part 60 of this chapter. For each fuel or consistent combination of fuels (and, optionally, for each combination of fuels), measure the NO_X and O_2 concentrations at each sampling point using methods 7E and 3A in appendices A-4 and A-2 to part 60 of this chapter. For diesel or dual fuel reciprocating engines, select the sampling site to be as close as practicable to the exhaust of the engine.

2.1.2.3 Allow the unit to stabilize for a minimum of 15 minutes (or longer if needed for the NO_X and O_2 readings to stabilize) prior to commencing NO_X, O_2, and heat input measurements. Determine the measurement system response time according to sections 8.2.5 and 8.2.6 of method 7E in appendix A-4 to part 60 of this chapter. When inserting the probe into the flue gas for the first sampling point in each traverse, sample for at least one minute plus twice the measurement system response time (or longer, if necessary to obtain a stable reading). For all other sampling points in each traverse, sample for at least one minute plus the measurement system response time (or longer, if necessary to obtain a stable reading). Perform three test runs at each load condition and obtain an arithmetic average of the runs for each load condition. During each test run on a boiler, record the boiler excess oxygen level at 5 minute intervals.

2.1.3 Heat Input

Measure the total heat input (mmBtu) and heat input rate during testing (mmBtu/hr) as follows:

2.1.3.1 When the unit is combusting fuel, measure and record the flow of fuel consumed. Measure the flow of fuel with an in-line flowmeter(s) and automatically record the data. If a portion of the flow is diverted from the unit without being burned, and that diversion occurs downstream of the fuel flowmeter, an in-line flowmeter is required to account for the unburned fuel. Install and calibrate in-line flow meters using the procedures and specifications contained in sections 2.1.2, 2.1.3, 2.1.4, and 2.1.5 of appendix D of this part. Correct any gaseous fuel flow rate measured at actual temperature and pressure to standard conditions of 68 °F and 29.92 inches of mercury.

2.1.3.2 For liquid fuels, analyze fuel samples taken according to the requirements of section 2.2 of appendix D of this part to determine the heat content of the fuel. Determine heat content of liquid or gaseous fuel in accordance with the procedures in appendix F of this part. Calculate the heat input rate during testing (mmBtu/hr) associated with each load condition in accordance with equations F-19 or F-20 in appendix F of this part and total heat input using equation E-1 of this appendix. Record the heat input rate at each heat input/load point.

2.1.4 Emergency Fuel

The designated representative of a unit that is restricted by its federal, State or local permit to combusting a particular fuel only during emergencies where the primary fuel is not available may claim an exemption from the requirements of this appendix for testing the NO_X emission rate during combustion of the emergency fuel. To claim this exemption, the designated representative shall include in the monitoring plan for the unit documentation that the permit restricts use of the fuel to emergencies only. When emergency fuel is combusted, report the maximum potential NO_X emission rate for the emergency fuel, in accordance with section 2.5.2.3 of this appendix. The designated representative shall also provide notice under §75.61(a)(6) for each period when the emergency fuel is combusted.

2.1.5 Tabulation of Results

Tabulate the results of each baseline correlation test for each fuel or, as applicable, combination of fuels, listing: time of test, duration, operating loads, heat input rate (mmBtu/hr), F-factors, excess oxygen levels, and NO_X concentrations (ppm) on a dry basis (at actual excess oxygen level). Convert the NO_X concentrations (ppm) to NO_X emission rates (to the nearest 0.001 lb/mm/Btu) according to equation F-5 of appendix F of this part or 19-3 in method 19 of appendix A of part 60 of this chapter, as appropriate. Calculate the NO_X emission rate in lb/mmBtu for each sampling point and determine the arithmetic average NO_X emission rate of each test run. Calculate the arithmetic average of the boiler excess oxygen readings for each test run. Record the arithmetic average of the three test runs as the NO_X emission rate and the boiler excess oxygen level for the heat input/load condition.

2.1.6 Plotting of Results

Plot the tabulated results as an x-y graph for each fuel and (as applicable) combination of fuels combusted according to the following procedures.

2.1.6.1 Plot the heat input rate (mmBtu/hr) as the independent (or x) variable and the NO_X emission rates (lb/mmBtu) as the dependent (or y) variable for each load point. Construct the graph by drawing straight line segments between each load point. Draw a horizontal line to the y-axis from the minimum heat input (load) point.

2.1.6.2 Units that co-fire gas and oil may be tested while firing gas only and oil only instead of testing with each combination of fuels. In this case, construct a graph for each fuel.

2.2 Periodic NO_X Emission Rate Testing

Retest the NO_X emission rate of the gas-fired peaking unit or the oil-fired peaking unit while combusting each type of fuel (or fuel mixture) for which a NO_X emission rate versus heat input rate correlation curve was derived, at least once every 20 calendar quarters. If a required retest is not completed by the end of the 20th calendar quarter following the quarter of the last test, use the missing data substitution procedures in section 2.5 of this appendix, beginning with the first unit operating hour after the end of the 20th calendar quarter. Continue using the missing data procedures until the required retest has been passed. Note that missing data substitution is fuel-specific (i.e., the use of substitute data is required only when combusting a fuel (or fuel mixture) for which the retesting deadline has not been met). Each time that a new fuel-specific correlation curve is derived from retesting, the new curve shall be used to report NO_X emission rate, beginning with the first operating hour in which the fuel is combusted, following the completion of the retest. Notwithstanding this requirement, for non-Acid Rain Program units that report NO_X mass emissions and heat input data only during the ozone season under §75.74(c), if the NO_X emission rate testing is performed outside the ozone season, the new correlation curve may be used beginning with the first unit operating hour in the ozone season immediately following the testing.

2.3 Other Quality Assurance/Quality Control-Related NOx Emission Rate Testing

When the operating levels of certain parameters exceed the limits specified below, or where the Administrator issues a notice requesting retesting because the NO_X emission rate data availability for when the unit operates within all quality assurance/quality control parameters in this section since the last test is less than 90.0 percent, as calculated by the Administrator, complete retesting of the NO_X emission rate by the earlier of: (1) 30 unit operating days (as defined in §72.2 of this chapter) or (2) 180 calendar days after exceeding the limits or after the date of issuance of a notice from the Administrator to re-verify the unit's NO_X emission rate. Submit test results in accordance with §75.60 within 45 days of completing the retesting.

2.3.1 For a stationary gas turbine, select at least four operating parameters indicative of the turbine's NO_X formation characteristics, and define in the QA plan for the unit the acceptable ranges for these parameters at each tested load-heat input point. The acceptable parametric ranges should be based upon the turbine manufacturer's recommendations. Alternatively, the owner or operator may use sound engineering judgment and operating experience with the unit to establish the acceptable parametric ranges, provided that the rationale for selecting these ranges is included as part of the quality-assurance plan for the unit. If the gas turbine uses water or steam injection for NO_X control, the water/fuel or steam/fuel ratio shall be one of these parameters. During the NOx-heat input correlation tests, record the average value of each parameter for each load-heat input to ensure that the parameters are within the acceptable range. Redetermine the NO_X emission rate-heat input correlation for each fuel and (optional) combination of fuels after continuously exceeding the acceptable range of any of these parameters for one or more successive operating periods totaling more than 16 unit operating hours.

2.3.2 For a diesel or dual-fuel reciprocating engine, select at least four operating parameters indicative of the engine's NO_X formation characteristics, and define in the QA plan for the unit the acceptable ranges for these parameters at each tested load-heat input point. The acceptable parametric ranges should be based upon the engine manufacturer's recommendations. Alternatively, the owner or operator may use sound engineering judgment and operating experience with the unit to establish the acceptable parametric ranges, provided that the rationale for selecting these ranges is included as part of the quality-assurance plan for the unit. Any operating parameter critical for NO_X control shall be included. During the NO_X heat-input correlation tests, record the average value of each parameter for each load-heat input to ensure that the parameters are within the acceptable range. Redetermine the NO_X emission rate-heat input correlation for each fuel and (optional) combination or fuels after continuously exceeding the acceptable range of any of these parameters for one or more successive operating periods totaling more than 16 unit operating hours.

2.3.3 For boilers using the procedures in this appendix, the NO_X emission rate heat input correlation for each fuel and (optional) combination of fuels shall be redetermined if the excess oxygen level at any heat input rate (or unit operating load) continuously exceeds by more than 2 percentage points O_2 from the boiler excess oxygen level recorded at the same operating heat input rate during the previous NO_X emission rate test for one or more successive operating periods totaling more than 16 unit operating hours.

2.4 Procedures for Determining Hourly NO_X Emission Rate

2.4.1 Record the time (hr. and min.), load (MWge or steam load in 1000 lb/hr, or mmBtu/hr thermal output), fuel flow rate and heat input rate (using the procedures in section 2.1.3 of this appendix) for each hour during which the unit combusts fuel. Calculate the total hourly heat input using equation E-1 of this appendix. Record the heat input rate for each fuel to the nearest 0.1 mmBtu/hr. During partial unit operating hours or during hours where more than one fuel is combusted, heat input must be represented as an hourly rate in mmBtu/hr, as if the fuel were combusted for the entire hour at that rate (and not as the actual, total heat input during that partial hour or hour) in order to ensure proper correlation with the NO_X emission rate graph.

2.4.2 Use the graph of the baseline correlation results (appropriate for the fuel or fuel combination) to determine the NO_X emissions rate (lb/mmBtu) corresponding to the heat input rate (mmBtu/hr). Input this correlation into the data acquisition and handling system for the unit. Linearly interpolate to 0.1 mmBtu/hr heat input rate and 0.001 lb/mmBtu NO_X. For each type of fuel, calculate NO_X emission rate using the baseline correlation results from the most recent test with that fuel, beginning with the date and hour of the completion of the most recent test.

2.4.3 To determine the NO_X emission rate for a unit co-firing fuels that has not been tested for that combination of fuels, interpolate between the NO_X emission rate for each fuel as follows. Determine the heat input rate for the hour (in mmBtu/hr) for each fuel and select the corresponding NO_X emission rate for each fuel on the appropriate graph. (When a fuel is combusted for a partial hour, determine the fuel usage time for each fuel and determine the heat input rate from each fuel as if that fuel were combusted at that rate for the entire hour in order to select the corresponding NO_X emission rate.) Calculate the total heat input to the unit in mmBtu for the hour from all fuel combusted using Equation E-1. Calculate a Btu-weighted average of the emission rates for all fuels using Equation E-2 of this appendix. For each type of fuel, calculate NO_X emission rate using the baseline correlation results from the most recent test with that fuel, beginning with the date and hour of the completion of the most recent test.

2.4.4 For each hour, record the critical quality assurance parameters, as identified in the monitoring plan, and as required by section 2.3 of this appendix from the date and hour of the completion of the most recent test for each type of fuel.

2.5 Missing Data Procedures

Provide substitute data for each unit electing to use this alternative procedure whenever a valid quality-assured hour of NO_X emission rate data has not been obtained according to the procedures and specifications of this appendix. For the purpose of providing substitute data, calculate the maximum potential NO_X emission rate (as defined in §72.2 of this chapter) for each type of fuel combusted in the unit.

2.5.1 Use the procedures of this section whenever any of the quality assurance/quality control parameters exceeds the limits in section 2.3 of this appendix or whenever any of the quality assurance/quality control parameters are not available.

2.5.2 Substitute missing NO_X emission rate data using the highest NO_X emission rate tabulated during the most recent set of baseline correlation tests for the same fuel or, if applicable, combination of fuels, except as provided in sections 2.5.2.1, 2.5.2.2, 2.5.2.3, and 2.5.2.4 of this appendix.

2.5.2.1 If the measured heat input rate during any unit operating hour is higher than the highest heat input rate from the baseline correlation tests, the NO_X emission rate for the hour is considered to be missing. Provide substitute data for each such hour, according to section 2.5.2.1.1 or 2.5.2.1.2 of this appendix, as applicable. Either:

2.5.2.1.1 Substitute the higher of: the NO_X emission rate obtained by linear extrapolation of the correlation curve, or the maximum potential NO_X emission rate (MER) (as defined in §72.2 of this chapter), specific to the type of fuel being combusted. (For fuel mixtures, substitute the highest NO_X MER value for any fuel in the mixture.) For units with NO_X emission controls, the extrapolated NO_X emission rate may only be used if the controls are documented (e.g., by parametric data) to be operating properly during the missing data period (see section 2.5.2.2 of this appendix); or

2.5.2.1.2 Substitute 1.25 times the highest NO_X emission rate from the baseline correlation tests for the fuel (or fuel mixture) being combusted in the unit, not to exceed the MER for that fuel (or mixture). For units with NO_X emission controls, the option to report 1.25 times the highest emission rate from the correlation curve may only be used if the controls are documented (e.g., by parametric data) to be operating properly during the missing data period (see section 2.5.2.2 of this appendix).

2.5.2.2 For a unit with add-on NO_X emission controls (e.g., steam or water injection, selective catalytic reduction), if, for any unit operating hour, the emission controls are either not in operation or if appropriate parametric data are unavailable to ensure proper operation of the controls, the NO_X emission rate for the hour is considered to be missing. Substitute the fuel-specific MER (as defined in §72.2 of this chapter) for each such hour.

2.5.2.3 When emergency fuel (as defined in §72.2) is combusted in the unit, report the fuel-specific NO_X MER for each hour that the fuel is combusted, unless a NO_X correlation curve has been derived for the fuel.

2.5.2.4 Whenever 20 full calendar quarters have elapsed following the quarter of the last baseline correlation test for a particular type of fuel (or fuel mixture), without a subsequent baseline correlation test being done for that type of fuel (or fuel mixture), substitute the fuel-specific NO_X MER (as defined in §72.2 of this chapter) for each hour in which that fuel (or mixture) is combusted until a new baseline correlation test for that fuel (or mixture) has been successfully completed. For fuel mixtures, report the highest of the individual MER values for the components of the mixture.

2.5.3 Maintain a record indicating which data are substitute data and the reasons for the failure to provide a valid quality-assured hour of NO_X emission rate data according to the procedures and specifications of this appendix.

2.5.4 Substitute missing data from a fuel flowmeter using the procedures in section 2.4.2 of appendix D to this part.

2.5.5 Substitute missing data for gross calorific value of fuel using the procedures in sections 2.4.1 of appendix D to this part.

3. Calculations

3.1 Heat Input

Calculate the total heat input by summing the product of heat input rate and fuel usage time of each fuel, as in the following equation:

$$H_T = HI_{fuel1} t_1 + HI_{fuel2} t_2 + HI_{fuel3} t_3 + \ldots + HI_{lastfuel} t_{last} \qquad (Eq.\ \text{E-1})$$

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Where:

H_T = Total heat input of fuel flow or a combination of fuel flows to a unit, mmBtu.

$HI_{fuel\ 1,2,3,...last}$ = Heat input rate from each fuel, in mmBtu/hr as determined using Equation F-19 or F-20 in section 5.5 of appendix F to this part, mmBtu/hr.

$t_{1,2,3....last}$ = Fuel usage time for each fuel (rounded up to the nearest fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator)).

3.2 F-factors

Determine the F-factors for each fuel or combination of fuels to be combusted according to section 3.3 of appendix F of this part.

3.3 NO_X Emission Rate

3.3.1 Conversion from Concentration to Emission Rate

Convert the NO_X concentrations (ppm) and O_2 concentrations to NO_X emission rates (to the nearest 0.01 lb/mmBtu for tests performed prior to April 1, 2000, or to the nearest 0.001 lb/mmBtu for tests performed on and after April 1, 2000), according to the appropriate one of the following equations: F-5 in appendix F to this part for dry basis concentration measurements or 19-3 in Method 19 of appendix A to part 60 of this chapter for wet basis concentration measurements.

3.3.2 Quarterly Average NO_X Emission Rate

Report the quarterly average emission rate (lb/mmBtu) as required in subpart G of this part. Calculate the quarterly average NO_X emission rate according to equation F-9 in appendix F of this part.

3.3.3 Annual Average NO_X Emission Rate

Report the average emission rate (lb/mmBtu) for the calendar year as required in subpart G of this part. Calculate the average NO_X emission rate according to equation F-10 in appendix F of this part.

3.3.4 Average NO_X Emission Rate During Co-firing of Fuels

$$E_h = \frac{\sum_{f=1}^{all\ fuels} \left(E_f \times HI_f t_f \right)}{H_T} \qquad (Eq.\ E\text{-}2)$$

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Where:

E_h = NO_X emission rate for the unit for the hour, lb/mmBtu.

E_f = NO_X emission rate for the unit for a given fuel at heat input rate HI_f, lb/mmBtu.

HI_f = Heat input rate for the hour for a given fuel, during the fuel usage time, as determined using Equation F-19 or F-20 in section 5.5 of appendix F to this part, mmBtu/hr.

H_T = Total heat input for all fuels for the hour from Equation E-1.

t_f = Fuel usage time for each fuel (rounded up to the nearest fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator)).

Note: For hours where a fuel is combusted for only part of the hour, use the fuel flow rate or mass flow rate during the fuel usage time, instead of the total fuel flow or mass flow during the hour, when calculating heat input rate using Equation F-19 or F-20.

4. Quality Assurance/Quality Control Plan

Include a section on the NO_X emission rate determination as part of the monitoring quality assurance/quality control plan required under §75.21 and appendix B of this part for each gas-fired peaking unit and each oil-fired peaking unit. In this section present information including, but not limited to, the following: (1) a copy of all data and results from the initial NO_X emission rate testing, including the values of quality assurance parameters specified in section 2.3 of this appendix; (2) a copy of all data and results from the most recent NO_X emission rate load correlation testing; (3) a copy of the recommended range of quality assurance- and quality control-related operating parameters.

4.1 Submit a copy of the recommended range of operating parameter values, and the range of operating parameter values recorded during the previous NO_X emission rate test that determined the unit's NO_X emission rate, along with the unit's revised monitoring plan submitted with the certification application.

4.2 Keep records of these operating parameters for each hour of operation in order to demonstrate that a unit is remaining within the recommended operating range.

[58 FR 3701, Jan. 11, 1993, as amended at 60 FR 26551, May 17, 1995; 64 FR 28665, May 26, 1999; 67 FR 40473, 40474, June 12, 2002; 67 FR 53505, Aug. 16, 2002; 73 FR 4372, Jan. 24, 2008; 76 FR 17325, Mar. 28, 2011]

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Appendix F to Part 75—Conversion Procedures

1. Applicability

Use the procedures in this appendix to convert measured data from a monitor or continuous emission monitoring system into the appropriate units of the standard.

2. Procedures for SO_2 Emissions

Use the following procedures to compute hourly SO_2 mass emission rate (in lb/hr) and quarterly and annual SO_2 total mass emissions (in tons).

2.1 When measurements of SO_2 concentration and flow rate are on a wet basis, use the following equation to compute hourly SO_2 mass emission rate (in lb/hr):

$$E_h = KC_hQ_h \qquad (Eq.\ F\text{-}1)$$

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Where:

E_h = Hourly SO_2 mass emission rate during unit operation, lb/hr.

K = 1.660×10^{-7} for SO_2, (lb/scf)/ppm.

C_h = Hourly average SO_2 concentration during unit operation, stack moisture basis, ppm.

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

2.2 When measurements by the SO_2 pollutant concentration monitor are on a dry basis and the flow rate monitor measurements are on a wet basis, use the following equation to compute hourly SO_2 mass emission rate (in lb/hr):

$$E_h = K\ C_{hp}Q_{hs}\frac{(100-\%H_2O)}{100} \qquad (Eq.\ F\text{-}2)$$

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where:

E_h = Hourly SO_2 mass emission rate during unit operation, lb/hr.

K = 1.660×10^{-7} for SO_2, (lb/scf)/ppm.

C_{hp} = Hourly average SO_2 concentration during unit operation, ppm (dry).

Q_{hs} = Hourly average volumetric flow rate during unit operation, scfh as measured (wet).

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

2.3 Use the following equations to calculate total SO_2 mass emissions for each calendar quarter (Equation F-3) and for each calendar year (Equation F-4), in tons:

$$E_q = \frac{\sum_{h=1}^{n} E_h t_h}{2000}$$

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(Eq. F-3)

Where:

E_q = Quarterly total SO_2 mass emissions, tons.

E_h = Hourly SO_2 mass emission rate, lb/hr.

t_h = 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).

n = Number of hourly SO_2 emissions values during calendar quarter.

2000 = Conversion of 2000 lb per ton.

$$E_a = \sum_{q=1}^{4} E_q \quad (Eq. F\text{-}4)$$

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Where:

E_a = Annual total SO_2 mass emissions, tons.

E_q = Quarterly SO_2 mass emissions, tons.

q = Quarters for which E_q are available during calendar year.

2.4 Round all SO_2 mass emission rates and totals to the nearest tenth.

3. Procedures for NO_X Emission Rate

Use the following procedures to convert continuous emission monitoring system measurements of NO_X concentration (ppm) and diluent concentration (percentage) into NO_X emission rates (in lb/mmBtu). Perform measurements of NO_X and diluent (O_2 or CO_2) concentrations on the same moisture (wet or dry) basis.

3.1 When the NO_X continuous emission monitoring system uses O_2 as the diluent, and measurements are performed on a dry basis, use the following conversion procedure:

$$E = K\, C_h\, F\, \frac{20.9}{20.9 - \%O_2}$$

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(Eq. F-5)

where,

K, E, C_h, F, and $\%O_2$ are defined in section 3.3 of this appendix. When measurements are performed on a wet basis, use the equations in Method 19 in appendix A-7 to part 60 of this chapter.

3.2 When the NO_X continuous emission monitoring system uses CO_2 as the diluent, use the following conversion procedure:

$$E = K\, C_h\, F_c\, \frac{100}{\%CO_2}$$

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(Eq. F-6)

where:

K, E, Ch, Fc, and $\%CO_2$ are defined in section 3.3 of this appendix.

When CO_2 and NO_X measurements are performed on a different moisture basis, use the equations in Method 19 in appendix A-7 to part 60 of this chapter.

3.3 Use the definitions listed below to derive values for the parameters in equations F-5 and F-6 of this appendix, or (if applicable) in the equations in Method 19 in appendix A-7 to part 60 of this chapter.

3.3.1 $K = 1.194 \times 10^{-7}$ (lb/dscf)/ppm NO_X.

3.3.2 E = Pollutant emissions during unit operation, lb/mmBtu.

3.3.3 C_h = Hourly average pollutant concentration during unit operation, ppm.

3.3.4 $\%O_2$, $\%CO_2$ = Oxygen or carbon dioxide volume during unit operation (expressed as percent O_2 or CO_2).

3.3.4.1 For boilers, a minimum concentration of 5.0 percent CO_2 or a maximum concentration of 14.0 percent O_2 may be substituted for the measured diluent gas concentration value for any operating hour in which the hourly average CO_2 concentration is <5.0 percent CO_2 or the hourly average O_2 concentration is >14.0 percent O_2. For stationary gas turbines, a minimum concentration of 1.0 percent CO_2 or a maximum concentration of 19.0 percent O_2 may be substituted for measured diluent gas concentration values for any operating hour in which the hourly average CO_2 concentration is <1.0 percent CO_2 or the hourly average O_2 concentration is >19.0 percent O_2.

3.3.4.2 If NO_X emission rate is calculated using either Equation 19-3 or 19-5 in Method 19 in appendix A-7 to part 60 of this chapter, a variant of the equation shall be used whenever the diluent cap is applied. The modified equations shall be designated as Equations 19-3D and 19-5D, respectively. Equation 19-3D is structurally the same as Equation 19-3, except that the term "$\%O_{2w}$" in the denominator is replaced with the term "$\%O_{2dc} \times [(100-\% H_2O)/100]$", where $\%O_{2dc}$ is the diluent cap value. The numerator of Equation 19-5D is the same as Equation 19-5; however, the denominator of Equation 19-5D is simply "$20.9-\%O_{2dc}$", where $\%O_{2dc}$ is the diluent cap value.

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_2 generated to the calorific value of the fuel combusted (F_c), respectively. Table 1 lists the values of F and F_c for different fuels.

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.

3.3.6 Equations F-7a and F-7b may be used in lieu of the F or F_c factors specified in Section 3.3.5 of this appendix to calculate a site-specific dry-basis F factor (dscf/mmBtu) or a site-specific F_c factor (scf CO_2/mmBtu), on either a dry or wet basis. At a minimum, the site-specific F or F_c factor must be based on 9 samples of the fuel. Fuel samples taken during each run of a RATA are acceptable for this purpose. The site-specific F or F_c factor must be re-determined at least annually, and the value from the most recent determination must be used in the emission calculations. Alternatively, the previous F or F_c value may continue to be used if it is higher than the value obtained in the most recent determination. The owner or operator shall keep records of all site-specific F or F_c determinations, active for at least 3 years. (Calculate all F- and F_c factors at standard conditions of 20 °C (68 °F) and 29.92 inches of mercury).

$$F = \frac{3.64(\%H) + 1.53(\%C) + 0.57(\%S) + 0.14(\%N) - 0.46(\%O)}{GCV} \times 10^6$$

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(Eq. F-7a)

$$F_c = \frac{321 \times 10^3 (\%C)}{GCV}$$

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(Eq. F-7b)

3.3.6.1 H, C, S, N, and O are content by weight of hydrogen, carbon, sulfur, nitrogen, and oxygen (expressed as percent), respectively, as determined on the same basis as the gross calorific value (GCV) by ultimate analysis of the fuel combusted using ASTM D3176-89 (Reapproved 2002), Standard Practice for Ultimate Analysis of Coal and Coke, (solid fuels), ASTM D5291-02, Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants, (liquid fuels) or computed from results using ASTM D1945-96 (Reapproved 2001), Standard Test Method for Analysis of Natural Gas by Gas Chromatography, or ASTM D1946-90 (Reapproved 2006), Standard Practice for Analysis of Reformed Gas by Gas Chromatography, (gaseous fuels) as applicable. (All of these methods are incorporated by reference under §75.6 of this part.)

3.3.6.2 GCV is the gross calorific value (Btu/lb) of the fuel combusted determined by ASTM D5865-01a or ASTM D5865-10, ASTM D240-00 or ASTM D4809-00, and ASTM D3588-98, ASTM D4891-89 (Reapproved 2006), GPA Standard 2172-96, GPA Standard 2261-00, or ASTM D1826-94 (Reapproved 1998), as applicable. (All of these methods are incorporated by reference under §75.6.)

3.3.6.3 For affected units that combust a combination of a fuel (or fuels) listed in Table 1 in section 3.3.5 of this appendix with any fuel(s) not listed in Table 1, the F or F_c value is subject to the Administrator's approval under §75.66.

3.3.6.4 For affected units that combust combinations of fuels listed in Table 1 in section 3.3.5 of this appendix, prorate the F or F_c factors determined by section 3.3.5 or 3.3.6 of this appendix in accordance with the applicable formula as follows:

$$F = \sum_{i=1}^{n} X_i F_i \quad F_c = \sum_{i=1}^{n} X_i (F_c)_i$$

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Where,

X_i = Fraction of total heat input derived from each type of fuel (*e.g.*, natural gas, bituminous coal, wood). Each X_i value shall be determined from the best available information on the quantity of fuel combusted and the GCV value, over a specified time period. The owner or operator shall explain the method used to calculate X_i in the hardcopy portion of the monitoring plan for the unit. The X_i values may be determined and updated either hourly, daily, weekly, or monthly. In all cases, the prorated F-factor used in the emission calculations shall be determined using the X_i values from the most recent update.

F_i or $(F_c)_i$ = Applicable F or Fc factor for each fuel type determined in accordance with Section 3.3.5 or 3.3.6 of this appendix.

n = Number of fuels being combusted in combination.

3.3.6.5 As an alternative to prorating the F or Fc factor as described in section 3.3.6.4 of this appendix, a "worst-case" F or F_c factor may be reported for any unit operating hour. The worst-case F or F_c factor shall be the highest F or F_c value for any of the fuels combusted in the unit.

3.4 Use the following equations to calculate the average NO_X emission rate for each calendar quarter (Equation F-9) and the average emission rate for the calendar year (Equation F-10), in lb/mmBtu:

$$E_q = \sum_{i=1}^{n} \frac{E_i}{n} \qquad (Eq.\ F\text{-}9)$$

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Where:

E_q = Quarterly average NO_X emission rate, lb/mmBtu.

E_i = Hourly average NO_X emission rate during unit operation, lb/mmBtu.

n = Number of hourly rates during calendar quarter.

$$E_a = \sum_{i=1}^{m} \frac{E_i}{m} \qquad (Eq.\ F\text{-}10)$$

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Where:

E_a = Average NO_X emission rate for the calendar year, lb/mmBtu.

E_i = Hourly average NO_X emission rate during unit operation, lb/mmBtu.

m = Number of hourly rates for which E_i is available in the calendar year.

3.5 Round all NO_X emission rates to the nearest 0.001 lb/mmBtu.

4. Procedures for CO_2 Mass Emissions

Use the following procedures to convert continuous emission monitoring system measurements of CO_2 concentration (percentage) and volumetric flow rate (scfh) into CO_2 mass emissions (in tons/day) when the owner or operator uses a CO_2 continuous emission monitoring system (consisting of a CO_2 or O_2 pollutant monitor) and a flow monitoring system to monitor CO_2 emissions from an affected unit.

4.1 When CO_2 concentration is measured on a wet basis, use the following equation to calculate hourly CO_2 mass emissions rates (in tons/hr):

$$E_h = KC_hQ_h \qquad (Eq.\ F\text{-}11)$$

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Where:

E_h = Hourly CO_2 mass emission rate during unit operation, tons/hr.

K = 5.7×10^{-7} for CO_2, (tons/scf) /%CO_2.

C_h = Hourly average CO_2 concentration during unit operation, wet basis, either measured directly with a CO_2 monitor or calculated from wet-basis O_2 data using Equation F-14b, percent CO_2.

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

4.2 When CO_2 concentration is measured on a dry basis, use Equation F-2 to calculate the hourly CO_2 mass emission rate (in tons/hr) with a K-value of 5.7×10^{-7} (tons/scf) percent CO_2, where E_h = hourly CO_2 mass emission rate, tons/hr and C_{hp} = hourly average CO_2 concentration in flue, dry basis, percent CO_2.

4.3 Use the following equations to calculate total CO_2 mass emissions for each calendar quarter (Equation F-12) and for each calendar year (Equation F-13):

$$E_{CO_2q} = \sum_{h=1}^{H_R} E_h t_h \qquad (Eq.\ F\text{-}12)$$

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Where:

E_{CO2q} = Quarterly total CO_2 mass emissions, tons.

E_h = Hourly CO_2 mass emission rate, tons/hr.

t_h = Unit operating time, in hours 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).

H_R = Number of hourly CO_2 mass emission rates available during calendar quarter.

$$E_{CO_2a} = \sum_{q=1}^{4} E_{CO_2q} \qquad (Eq.\ F\text{-}13)$$

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Where:

E_{CO2a} = Annual total CO_2 mass emissions, tons.

E_{CO2q} = Quarterly total CO_2 mass emissions, tons.

q = Quarters for which E_{CO2q} are available during calendar year.

4.4 For an affected unit, when the owner or operator is continuously monitoring O_2 concentration (in percent by volume) of flue gases using an O_2 monitor, use the equations and procedures in section 4.4.1 and 4.4.2 of this appendix to determine hourly CO_2 mass emissions (in tons).

4.4.1 If the owner or operator elects to use data from an O_2 monitor to calculate CO_2 concentration, the appropriate F and F_C factors from section 3.3.5 of this appendix shall be used in one of the following equations (as applicable) to determine hourly average CO_2 concentration of flue gases (in percent by volume) from the measured hourly average O_2 concentration:

$$CO_{2d} = 100 \frac{F_c}{F} \frac{20.9 - O_{2d}}{20.9} \qquad \text{(Eq. F-14a)}$$

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Where:

CO_{2d} = Hourly average CO_2 concentration during unit operation, percent by volume, dry basis.

F, F_C = F-factor or carbon-based F_c-factor from section 3.3.5 of this appendix.

20.9 = Percentage of O_2 in ambient air.

O_{2d} = Hourly average O_2 concentration during unit operation, percent by volume, dry basis.

$$CO_{2w} = \frac{100}{20.9} \frac{F_c}{F} \left[20.9 \left(\frac{100 - \%H_2O}{100} \right) - O_{2w} \right] \qquad \text{(Eq. F-14b)}$$

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Where:

CO_{2w} = Hourly average CO_2 concentration during unit operation, percent by volume, wet basis.

O_{2w} = Hourly average O_2 concentration during unit operation, percent by volume, wet basis.

F, F_c = F-factor or carbon-based FC-factor from section 3.3.5 of this appendix.

20.9 = Percentage of O_2 in ambient air.

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

For any hour where Equation F-14a or F-14b results in a negative hourly average CO_2 value, 0.0% CO_{2w} shall be recorded as the average CO_2 value for that hour.

4.4.2 Determine CO_2 mass emissions (in tons) from hourly average CO_2 concentration (percent by volume) using equation F-11 and the procedure in section 4.1, where O_2 measurements are on a wet basis, or using the procedures in section 4.2 of this appendix, where O_2 measurements are on a dry basis.

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_2 or 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_2 concentration are on a wet basis, use the following equation:

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

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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_2 during unit operation, percent CO_2 wet basis.

5.2.2 When measurements of CO_2 concentration are on a dry basis, use the following equation:

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

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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_2 during unit operation, percent CO_2 dry basis.

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

5.2.3 When measurements of O_2 concentration are on a wet basis, use the following equation:

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

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

$\%O_{2w}$ = Hourly concentration of O_2 during unit operation, percent O_2 wet 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_2 concentration are on a dry basis, use the following equation:

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

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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 section 3.3.5 of this appendix for each fuel, dscf/mmBtu.

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

$\%O_{2d}$ = Hourly concentration of O_2 during unit operation, percent O_2 dry 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:

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

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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:

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

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Where:

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

HI_q = Total heat input for the quarter, mmBtu.

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_2 emissions 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:

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

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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, ASTM D5865-10, 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).

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:

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

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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.

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. Use ASTM D2013-01 for preparation of a daily coal sample and analyze each daily coal sample for gross calorific value using ASTM D5865-01a or ASTM D5865-10. 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:

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

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(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), ASTM D5865-01a, or ASTM D5865-10, Btu/lb (incorporated by reference under §75.6).

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

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:

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

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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:

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

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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

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:

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

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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:

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

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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.

6. Procedure for Converting Volumetric Flow to STP

Use the following equation to convert volumetric flow at actual temperature and pressure to standard temperature and pressure.

$F_{STP} = F_{Actual}(T_{Std}/T_{Stack})(P_{Stack}/P_{Std})$

where:

F_{STP} = Flue gas volumetric flow rate at standard temperature and pressure, scfh.

F_{Actual} = Flue gas volumetric flow rate at actual temperature and pressure, acfh.

T_{Std} = Standard temperature = 528 °R.

T_{Stack} = Flue gas temperature at flow monitor location, °R, where °R = 460 + °F.

P_{Stack} = The absolute flue gas pressure = barometric pressure at the flow monitor location + flue gas static pressure, inches of mercury.

P_{Std} = Standard pressure = 29.92 inches of mercury.

7. Procedures for SO_2 Mass Emissions, Using Default SO_2 Emission Rates and Heat Input Measured by CEMS

The owner or operator shall use Equation F-23 to calculate hourly SO_2 mass emissions in accordance with §75.11(e)(1) during the combustion of gaseous fuel, for a unit that uses a flow monitor and a diluent gas monitor to measure heat input, and that qualifies to use a default SO_2 emission rate under section 2.3.1.1, 2.3.2.1.1, or 2.3.6(b) of appendix D to this part. Equation F-23 may also be applied to the combustion of solid or liquid fuel that meets the definition of very low sulfur fuel in §72.2 of this chapter, combinations of such fuels, or mixtures of such fuels with gaseous fuel, if the owner or operator has received approval from the Administrator under §75.66 to use a site-specific default SO_2 emission rate for the fuel or mixture of fuels.

$$E_h = (ER)(HI) \qquad \text{(Eq. F-23)}$$

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Where:

E_h = Hourly SO_2 mass emission rate, lb/hr.

ER = Applicable SO_2 default emission rate for gaseous fuel combustion, from section 2.3.1.1, 2.3.2.1.1, or 2.3.6(b) of appendix D to this part, or other default SO_2 emission rate for the combustion of very low sulfur liquid or solid fuel, combinations of such fuels, or mixtures of such fuels with gaseous fuel, as approved by the Administrator under §75.66, lb/mmBtu.

HI = Hourly heat input rate, determined using the procedures in section 5.2 of this appendix, mmBtu/hr.

8. Procedures for NO_X Mass Emissions

The owner or operator of a unit that is required to monitor, record, and report NO_X mass emissions under a State or federal NO_X mass emission reduction program must use the procedures in section 8.1, 8.2, or 8.3 of this appendix, as applicable, to account for hourly NO_X mass emissions, and the procedures in section 8.4 of this appendix to account for quarterly, seasonal, and annual NO_X mass emissions to the extent that the provisions of subpart H of this part are adopted as requirements under such a program.

8.1 The owner or operator may use the hourly NO_X emission rate and the hourly heat input rate to calculate the NO_X mass emissions in pounds or the NO_X mass emission rate in pounds per hour, (as required by the applicable reporting format), for each unit or stack operating hour, as follows:

8.1.1 If both NO_X emission rate and heat input rate are monitored at the same unit or stack level (e.g., the NO_X emission rate value and the heat input rate value both represent all of the units exhausting to the common stack), then (as required by the applicable reporting format) either:

(a) Use Equation F-24 to calculate the hourly NO_X mass emissions (lb).

$$M_{(NOx)h} = ER_{(NOx)h} HI_h t_h \qquad \text{(Eq. F-24)}$$

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Where:

$M_{(NOx)h}$ = NO_X mass emissions in lbs for the hour.

$ER_{(NOx)h}$ = Hourly average NO_X emission rate for hour h, lb/mmBtu, from section 3 of this appendix, from Method 19 in appendix A-7 to part 60 of this chapter, or from section 3.3 of appendix E to this part. (Include bias-adjusted NO_X emission rate values, where the bias-test procedures in appendix A to this part shows a bias-adjustment factor is necessary.)

HI_h = Hourly average heat input rate for hour h, mmBtu/hr. (Include bias-adjusted flow rate values, where the bias-test procedures in appendix A to this part shows a bias-adjustment factor is necessary.)

t_h = Monitoring location operating time for hour h, in hours 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). If the combined NO_X emission rate and heat input are monitored for all of the units in a common stack, the monitoring location operating time is equal to the total time when any of those units was exhausting through the common stack; or

(b) Use Equation F-24a to calculate the hourly NO_X mass emission rate (lb/hr).

$$E_{(NOx)h} = ER_{(NOx)h} HI_h \qquad \text{(Eq. F-24a)}$$

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Where:

$E_{(NOx)h}$ = NO_X mass emissions rate in lbs/hr for the hour.

$ER_{(NOx)h}$ = Hourly average NO_X emission rate for hour h, lb/mmBtu, from section 3 of this appendix, from Method 19 in appendix A-7 to part 60 of this chapter, or from section 3.3 of appendix E to this part. (Include bias-adjusted NO_X emission rate values, where the bias-test procedures in appendix A to this part shows a bias-adjustment factor is necessary.)

HI_h = Hourly average heat input rate for hour h, mmBtu/hr. (Include bias-adjusted flow rate values, where the bias-test procedures in appendix A to this part shows a bias-adjustment factor is necessary.)

8.1.2 If NO_X emission rate is measured at a common stack and heat input is measured at the unit level, sum the hourly heat inputs at the unit level according to the following formula:

$$HI_{CS} = \frac{\sum_{u=1}^{p} HI_u t_u}{t_{CS}} \qquad (Eq.\ F\text{-}25)$$

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where:

HI_{CS} = Hourly average heat input rate for hour h for the units at the common stack, mmBtu/hr.

t_{CS} = Common stack operating time for hour h, in hours 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). (For each hour, t_{cs} is the total time during which one or more of the units which exhaust through the common stack operate.).

HI_u = Hourly average heat input rate for hour h for the unit, mmBtu/hr.

t_u = Unit operating time for hour h, in hours 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).

p = Number of units that exhaust through the common stack.

u = Designation of a particular unit.

Use the hourly heat input rate at the common stack level and the hourly average NO_X emission rate at the common stack level and the procedures in section 8.1.1 of this appendix to determine the hourly NO_X mass emissions at the common stack.

8.1.3 If a unit has multiple ducts and NO_X emission rate is only measured at one duct, use the NO_X emission rate measured at the duct, the heat input measured for the unit, and the procedures in section 8.1.1 of this appendix to determine NO_X mass emissions.

8.1.4 If a unit has multiple ducts and NO_X emission rate is measured in each duct, heat input shall also be measured in each duct and the procedures in section 8.1.1 of this appendix shall be used to determine NO_X mass emissions.

8.2 Alternatively, the owner or operator may use the hourly NO_X concentration (as measured by a NO_X concentration monitoring system) and the hourly stack gas volumetric flow rate to calculate the NO_X mass emission rate (lb/hr) for each unit or stack operating hour, in accordance with section 8.2.1 or 8.2.2 of this appendix (as applicable). If the hourly NO_X mass emissions are to be reported in lb, Equation F-26c in section 8.3 of this appendix shall be used to convert the hourly NO_X mass emission rates to hourly NO_X mass emissions (lb).

8.2.1 When the NO_X concentration monitoring system measures on a wet basis, first calculate the hourly NO_X mass emission rate (in lb/hr) during unit (or stack) operation, using Equation F-26a. (Include bias-adjusted flow rate or NO_X concentration values, where the bias-test procedures in appendix A to this part shows a bias-adjustment factor is necessary.)

$$E_{(NO_x)_h} = K\ C_{hw} Q_h \qquad \text{(Eq. F-26a)}$$

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Where:

$E_{(NOx)h}$ = NO_X mass emissions rate in lb/hr.

K = 1.194×10^{-7} for NO_X, (lb/scf)/ppm.

C_{hw} = Hourly average NO_X concentration during unit operation, wet basis, ppm.

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

8.2.2 When NO_X mass emissions are determined using a dry basis NO_X concentration monitoring system and a wet basis flow monitoring system, first calculate hourly NO_X mass emission rate (in lb/hr) during unit (or stack) operation, using Equation F-26b. (Include bias-adjusted flow rate or NO_X concentration values, where the bias-test procedures in appendix A to this part shows a bias-adjustment factor is necessary.)

$$E_{(NO_x)_h} = K\ C_{hd} Q_h \frac{(100 - \%H_2O)}{(100)} \qquad \text{(Eq. F-26b)}$$

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Where:

$E_{(NOx)h}$ = NO_X mass emissions rate, lb/hr.

K = 1.194×10^{-7} for NO_X, (lb/scf)/ppm.

C_{hd} = Hourly average NO_X concentration during unit operation, dry basis, ppm.

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

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

8.3 When hourly NO_X mass emissions are reported in pounds and are determined using a NO_X concentration monitoring system and a flow monitoring system, calculate NO_X mass emissions (lb) for each unit or stack operating hour by multiplying the hourly NO_X mass emission rate (lb/hr) by the unit operating time for the hour, as follows:

$$M_{(NO_x)_h} = E_h t_h \qquad \text{(Eq. F-26c)}$$

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Where:

$M_{(NOx)h}$ = NO_X mass emissions for the hour, lb.

E_h = Hourly NO_X mass emission rate during unit (or stack) operation from Equation F-26a in section 8.2.1 of this appendix or Equation F-26b in section 8.2.2 of this appendix (as applicable), lb/hr.

t_h = Unit operating time or stack operating time (as defined in §72.2 of this chapter) for hour "h", in hours 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).

8.4 Use the following procedures to calculate quarterly, cumulative ozone season, and cumulative yearly NO_X mass emissions, in tons:

(a) When hourly NO_X mass emissions are reported in lb., use Eq. F-27.

$$M_{(NO_x)_{time\ period}} = \frac{\sum_{h=1}^{p} M(NO_x)_h}{2000} \quad \text{(Eq. F-27)}$$

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Where:

$M_{(NOx)_{time\ period}}$ = NO_X mass emissions in tons for the given time period (quarter, cumulative ozone season, cumulative year-to-date).

$M_{(NOx)_h}$ = NO_X mass emissions in lb for the hour.

p = The number of hours in the given time period (quarter, cumulative ozone season, cumulative year-to-date).

(b) When hourly NO_X mass emission rate is reported in lb/hr, use Eq. F-27a.

$$M_{(NO_x)_{time\ period}} = \frac{\sum_{h=1}^{p} E_{(NO_x)_h} t_h}{2000} \quad \text{(Eq. F-27a)}$$

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Where:

$M_{(NOx)_{time\ period}}$ = NO_X mass emissions in tons for the given time period (quarter, cumulative ozone season, cumulative year-to-date).

$E_{(NOx)_h}$ = NO_X mass emission rate in lb/hr for the hour.

p = The number of hours in the given time period (quarter, cumulative ozone season, cumulative year-to-date).

t_h = Monitoring location operating time for hour h, in hours 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).

8.5 Specific provisions for monitoring NO_X mass emissions from common stacks. The owner or operator of a unit utilizing a common stack may account for NO_X mass emissions using either of the following methodologies, if the provisions of subpart H are adopted as requirements of a State or federal NO_X mass reduction program:

8.5.1 The owner or operator may determine both NO_X emission rate and heat input at the common stack and use the procedures in section 8.1.1 of this appendix to determine hourly NO_X mass emissions at the common stack.

8.5.2 The owner or operator may determine the NO_X emission rate at the common stack and the heat input at each of the units and use the procedures in section 8.1.2 of this appendix to determine the hourly NO_X mass emissions at each unit.

9. [Reserved]

10. Moisture Determination From Wet and Dry O_2 Readings

If a correction for the stack gas moisture content is required in any of the emissions or heat input calculations described in this appendix, and if the hourly moisture content is determined from wet- and dry-basis O_2 readings, use Equation F-31 to calculate the percent moisture, unless a "K" factor or other mathematical algorithm is developed as described in section 6.5.7(a) of appendix A to this part:

$$\%H_2O = \frac{(O_{2d} - O_{2w})}{O_{2d}} \times 100 \quad \text{(Eq. F-31)}$$

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Where:

% H_2O = Hourly average stack gas moisture content, percent H_2O

O_{2d} = Dry-basis hourly average oxygen concentration, percent O_2

O_{2w} = Wet-basis hourly average oxygen concentration, percent O_2

[58 FR 3701, Jan. 11, 1993; Redesignated and amended at 60 FR 26553, 26571, May 17, 1995; 61 FR 25585, May 22, 1996; 61 FR 59166, Nov. 20, 1996; 63 FR 57513, Oct. 27, 1998; 64 FR 28666, May 26, 1999; 64 FR 37582, July 12, 1999; 67 FR 40474, 40475, June 12, 2002; 67 FR 53505, Aug. 16, 2002; 70 FR 28695, May 18, 2005; 73 FR 4372, Jan. 24, 2008; 76 FR 17325, Mar. 28, 2011; 77 FR 2460, Jan. 18, 2012]

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Appendix G to Part 75—Determination of CO_2 Emissions

1. Applicability

The procedures in this appendix may be used to estimate CO_2 mass emissions discharged to the atmosphere (in tons/day) as the sum of CO_2 emissions from combustion and, if applicable, CO_2 emissions from sorbent used in a wet flue gas desulfurization control system, fluidized bed boiler, or other emission controls.

2. Procedures for Estimating CO_2 Emissions From Combustion

Use the following procedures to estimate daily CO_2 mass emissions from the combustion of fossil fuels. The optional procedure in section 2.3 of this appendix may also be used for an affected gas-fired unit. For an affected unit that combusts any nonfossil fuels (e.g., bark, wood, residue, or refuse), either use a CO_2 continuous emission monitoring system or apply to the Administrator for approval of a unit-specific method for determining CO_2 emissions.

2.1 Use the following equation to calculate daily CO_2 mass emissions (in tons/day) from the combustion of fossil fuels. Where fuel flow is measured in a common pipe header (i.e., a pipe carrying fuel for multiple units), the owner or operator may use the procedures in section 2.1.2 of appendix D of this part for combining or apportioning emissions, except that the term "SO_2 mass emissions" is replaced with the term "CO_2 mass emissions."

$$W_{CO_2} = \frac{\left(MW_C + MW_{O_2}\right) \times W_C}{2,000\, MW_C} \quad (Eq.\ G\text{-}1)$$

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Where:

Wco2 = CO_2 emitted from combustion, tons/day.

MW_c = Molecular weight of carbon (12.0).

MW_{o2} = Molecular weight of oxygen (32.0)

W_c = Carbon burned, lb/day, determined using fuel sampling and analysis and fuel feed rates.

2.1.1 Collect at least one fuel sample during each week that the unit combusts coal, one sample per each shipment or delivery for oil and diesel fuel, one fuel sample for each delivery for gaseous fuel in lots, one sample per day or per hour (as applicable) for each gaseous fuel that is required to be sampled daily or hourly for gross calorific value under section 2.3.5.6 of appendix D to this part, and one sample per month for each gaseous fuel that is required to be sampled monthly for gross calorific value under section 2.3.4.1 or 2.3.4.2 of appendix D to this part. Collect coal samples from a location in the fuel handling system that provides a sample representative of the fuel bunkered or consumed during the week.

2.1.2 Determine the carbon content of each fuel sample using one of the following methods: ASTM D3178-89 (Reapproved 2002) or ASTM D5373-02 (Reapproved 2007) for coal; ASTM D5291-02, Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants, ultimate analysis of oil, or computations based upon ASTM D3238-95 (Reapproved 2000) and either ASTM D2502-92 (Reapproved 1996) or ASTM D2503-92 (Reapproved 1997) for oil; and computations based on ASTM D1945-96 (Reapproved 2001) or ASTM D1946-90 (Reapproved 2006) for gas (all incorporated by reference under §75.6 of this part).

2.1.3 Use daily fuel feed rates from company records for all fuels and the carbon content of the most recent fuel sample under this section to determine tons of carbon per day from combustion of each fuel. (All ASTM methods are incorporated by reference under §75.6.) Where more than one fuel is combusted during a calendar day, calculate total tons of carbon for the day from all fuels.

2.2 For an affected coal-fired unit, the estimate of daily CO_2 mass emissions given by equation G-1 may be adjusted to account for carbon retained in the ash using the procedures in either section 2.2.1 through 2.2.3 or section 2.2.4 of this appendix.

2.2.1 Determine the ash content of the weekly sample of coal using ASTM D3174-00, "Standard Test Method for Ash in the Analysis Sample of Coal and Coke from Coal" (incorporated by reference under §75.6 of this part).

2.2.2 Sample and analyze the carbon content of the fly-ash according to ASTM D5373-02 (Reapproved 2007), Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal and Coke" (incorporated by reference under §75.6 of this part).

2.2.3 Discount the estimate of daily CO_2 mass emissions from the combustion of coal given by equation G-1 by the percent carbon retained in the ash using the following equation:

$$W_{NCO2} = W_{CO2} - \left(\frac{MW_{CO2}}{MW_c}\right)\left(\frac{A\%}{100}\right)\left(\frac{C\%}{100}\right)W_{COAL}$$

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(Eq. G-2)

where,

W_{NCO2} = Net CO_2 mass emissions discharged to the atmosphere, tons/day.

W_{CO2} = Daily CO_2 mass emissions calculated by equation G-1, tons/day.

MW_{C02} = Molecular weight of carbon dioxide (44.0).

MW_c = Molecular weight of carbon (12.0).

A% = Ash content of the coal sample, percent by weight.

C% = Carbon content of ash, percent by weight.

W_{COAL} = Feed rate of coal from company records, tons/day.

2.2.4 The daily CO_2 mass emissions from combusting coal may be adjusted to account for carbon retained in the ash using the following equation:

$W_{NCO2} = .99\ W_{CO2}$

(Eq. G-3)

where,

W_{NCO2} = Net CO_2 mass emissions from the combustion of coal discharged to the atmosphere, tons/day.

.99 = Average fraction of coal converted into CO_2 upon combustion.

W_{CO2} = Daily CO_2 mass emissions from the combustion of coal calculated by equation G-1, tons/day.

2.3 In lieu of using the procedures, methods, and equations in section 2.1 of this appendix, the owner or operator of an affected gas-fired or oil-fired unit (as defined under §72.2 of this chapter) may use the following equation and records of hourly heat input to estimate hourly CO_2 mass emissions (in tons).

$$W_{CO_2} = \left(\frac{F_C \times H \times U_f \times MW_{CO_2}}{2000}\right) \qquad (Eq.\ G\text{–}4)$$

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(Eq. G-4)

Where:

WCO_2 = CO_2 emitted from combustion, tons/hr.

MW CO_2 = Molecular weight of carbon dioxide, 44.0 lb/lb-mole.

F_c = Carbon based F-factor, 1040 scf/mmBtu for natural gas; 1,420 scf/mmBtu for crude, residual, or distillate oil; and calculated according to the procedures in section 3.3.5 of appendix F to this part for other gaseous fuels.

H = Hourly heat input in mmBtu, as calculated using the procedures in section 5 of appendix F of this part.

Uf = 1/385 scf CO2/lb-mole at 14.7 psia and 68 °F.

3. Procedures for Estimating CO_2 Emissions From Sorbent

When the affected unit has a wet flue gas desulfurization system, is a fluidized bed boiler, or uses other emission controls with sorbent injection, use either a CO_2 continuous emission monitoring system or an O_2 monitor and a flow monitor, or use the procedures, methods, and equations in sections 3.1 through 3.2 of this appendix to determine daily CO_2 mass emissions from the sorbent (in tons).

3.1 When limestone is the sorbent material, use the equations and procedures in either section 3.1.1 or 3.1.2 of this appendix.

3.1.1 Use the following equation to estimate daily CO_2 mass emissions from sorbent (in tons).

$$SE_{CO_2} = W_{CaCO_3}\, F_u\, \frac{MW_{CO_2}}{MW_{CaCO_3}}$$

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(Eq. G-5)

where,

SE_{CO2} = CO_2 emitted from sorbent, tons/day.

W_{CaCO3} = $CaCO_3$ used, tons/day.

F_u = 1.00, the calcium to sulfur stoichiometric ratio.

MW_{CO2} = Molecular weight of carbon dioxide (44).

MW_{CaCO3} = Molecular weight of calcium carbonate (100).

3.1.2 In lieu of using Equation G-5, any owner or operator who operates and maintains a certified SO_2-diluent continuous emission monitoring system (consisting of an SO_2 pollutant concentration monitor and an O_2 or CO_2 diluent gas monitor), for measuring and recording SO_2 emission rate (in lb/mmBtu) at the outlet to the emission controls and who uses the applicable procedures, methods, and equations such as those in EPA Method 19 in appendix A to part 60 of this chapter to estimate the SO_2 emissions removal efficiency of the emission controls, may use the following equations to estimate daily CO_2 mass emissions from sorbent (in tons).

$$SE_{CO_2} = F_u\, \frac{W_{SO_2}}{2000}\, \frac{MW_{CO_2}}{MW_{SO_2}}$$

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(Eq. G-6)

where,

SE_{CO2} = CO_2 emitted from sorbent, tons/day.

MW_{CO2} = Molecular weight of carbon dioxide (44).

MW_{SO2} = Molecular weight of sulfur dioxide (64).

W_{SO2} = Sulfur dioxide removed, lb/day, as calculated below using Eq. G-7.

F_u = 1.0, the calcium to sulfur stoichiometric ratio.

and

$$W_{SO_2} = SO_{2o} \frac{\%R}{(100 - \%R)} \qquad (Eq.\ G\text{-}7)$$

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(Eq. G-7)

where:

WSO_2 = Weight of sulfur dioxide removed, lb/day.

SO_{20} = SO_2 mass emissions monitored at the outlet, lb/day, as calculated using the equations and procedures in section 2 of appendix F of this part.

%R = Overall percentage SO_2 emissions removal efficiency, calculated using equations such as those in EPA Method 19 in appendix A to part 60 of this chapter, and using daily instead of annual average emission rates.

3.2 When a sorbent material other than limestone is used, modify the equations, methods, and procedures in section 3.1 of this appendix as follows to estimate daily CO_2 mass emissions from sorbent (in tons).

3.2.1 Determine a site-specific value for F_u, defined as the ratio of the number of moles of CO_2 released upon capture of one mole of SO_2, using methods and procedures satisfactory to the Administrator. Use this value of F_u (instead of 1.0) in either equation G-5 or equation G-6.

3.2.2 When using equation G-5, replace MW_{CaCO3}, the molecular weight of calcium carbonate, with the molecular weight of the sorbent material that participates in the reaction to capture SO_2 and that releases CO_2, and replace W_{CaCO3}, the amount of calcium carbonate used (in tons/day), with the amount of sorbent material used (in tons/day).

4. Procedures for Estimating Total CO_2 Emissions

When the affected unit has a wet flue gas desulfurization system, is a fluidized bed boiler, or uses other emission controls with sorbent injection, use the following equation to obtain total daily CO_2 mass emissions (in tons) as the sum of combustion-related emissions and sorbent-related emissions.

$W_t = W_{CO2} + SE_{CO2}$

(Eq. G-8)

where,

W_t = Estimated total CO_2 mass emissions, tons/day.

W_{CO2} = CO_2 emitted from fuel combustion, tons/day.

SE_{CO2} = CO_2 emitted from sorbent, tons/day.

5. Missing Data Substitution Procedures for Fuel Analytical Data

Use the following procedures to substitute for missing fuel analytical data used to calculate CO_2 mass emissions under this appendix.

5.1-5.1.2 [Reserved]

5.2 Missing Carbon Content Data

Use the following procedures to substitute for missing carbon content data.

5.2.1 In all cases (i.e., for weekly coal samples or composite oil samples from continuous sampling, for oil samples taken from the storage tank after transfer of a new delivery of fuel, for as-delivered samples of oil, diesel fuel, or gaseous fuel delivered in lots, and for gaseous fuel that is supplied by a pipeline and sampled monthly, daily or hourly for gross calorific value) when carbon content data is missing, report the appropriate default value from Table G-1.

5.2.2 The missing data values in Table G-1 shall be reported whenever the results of a required sample of fuel carbon content are either missing or invalid. The substitute data value shall be used until the next valid carbon content sample is obtained.

TABLE G-1. -- MISSING DATA SUBSTITUTION PROCEDURES FOR MISSING CARBON CONTENT DATA

Parameter	Missing data value
Oil and coal carbon content	Most recent, previous carbon content value available for that type of coal, grade of oil, or default value, in this table
Gas carbon content	Most recent, previous carbon content value available for that type of gaseous fuel, or default value, in this table
Default coal carbon content	Anthracite: 90.0 percent
	Bituminous: 85.0 percent
	Subbituminous/Lignite: 75.0 percent
Default oil carbon content	90.0 percent
Default gas carbon content	Natural gas: 75.0 percent
	Other gaseous fuels: 90.0 percent

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5.3 Gross Calorific Value Data

For a gas-fired unit using the procedures of section 2.3 of this appendix to determine CO_2 emissions, substitute for missing gross calorific value data used to calculate heat input by following the missing data procedures for gross calorific value in section 2.4 of appendix D to this part.

[58 FR 3701, Jan. 11, 1993, as amended at 60 FR 26556, May 17, 1995; 61 FR 25585, May 22, 1996; 64 FR 28671, May 26, 1999; 67 FR 40475, June 12, 2002; 67 FR 57274, Sept. 9, 2002; 73 FR 4376, Jan. 24, 2008]

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Appendix H to Part 75—Revised Traceability Protocol No. 1 [Reserved]

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Appendix I to Part 75—Optional F—Factor/Fuel Flow Method [Reserved]

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Appendix J to Part 75—Compliance Dates for Revised Recordkeeping Requirements and Missing Data Procedures [Reserved]

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Performance Specification 2—Specifications and Test Procedures for SO_2 and NO_X Continuous Emission Monitoring Systems in Stationary Sources

1.0 Scope and Application

1.1 Analytes

Analyte	CAS Nos.
Sulfur Dioxide (SO_2)	7449-09-5
Nitrogen Oxides (NO_X)	10102-44-0 (NO_2), 10024-97-2 (NO)

1.2 Applicability.

1.2.1 This specification is for evaluating the acceptability of SO_2 and NO_X continuous emission monitoring systems (CEMS) at the time of installation or soon after and whenever specified in the regulations. The CEMS may include, for certain stationary sources, a diluent (O_2 or CO_2) monitor.

1.2.2 This specification is not designed to evaluate the installed CEMS performance over an extended period of time nor does it identify specific calibration techniques and other auxiliary procedures to assess the CEMS performance. The source owner or operator is responsible to calibrate, maintain, and operate the CEMS properly. The Administrator may require, under section 114 of the Act, the operator to conduct CEMS performance evaluations at other times besides the initial test to evaluate the CEMS performance. See 40 CFR Part 60, §60.13(c).

2.0 Summary of Performance Specification

Procedures for measuring CEMS relative accuracy and calibration drift are outlined. CEMS installation and measurement location specifications, equipment specifications, performance specifications, and data reduction procedures are included. Conformance of the CEMS with the Performance Specification is determined.

3.0 Definitions

3.1 *Calibration Drift (CD)* means the difference in the CEMS output readings from the established reference value after a stated period of operation during which no unscheduled maintenance, repair, or adjustment took place.

3.2 *Centroidal Area* means a concentric area that is geometrically similar to the stack or duct cross section and is no greater than l percent of the stack or duct cross-sectional area.

3.3 *Continuous Emission Monitoring System* means the total equipment required for the determination of a gas concentration or emission rate. The sample interface, pollutant analyzer, diluent analyzer, and data recorder are the major subsystems of the CEMS.

3.4 *Data Recorder* means that portion of the CEMS that provides a permanent record of the analyzer output. The data recorder may include automatic data reduction capabilities.

3.5 *Diluent Analyzer* means that portion of the CEMS that senses the diluent gas (*i.e.,* CO_2 or O_2) and generates an output proportional to the gas concentration.

3.6 *Path CEMS* means a CEMS that measures the gas concentration along a path greater than 10 percent of the equivalent diameter of the stack or duct cross section.

3.7 *Point CEMS* means a CEMS that measures the gas concentration either at a single point or along a path equal to or less than 10 percent of the equivalent diameter of the stack or duct cross section.

3.8 *Pollutant Analyzer* means that portion of the CEMS that senses the pollutant gas and generates an output proportional to the gas concentration.

3.9 *Relative Accuracy (RA)* means the absolute mean difference between the gas concentration or emission rate determined by the CEMS and the value determined by the reference method (RM), plus the 2.5 percent error confidence coefficient of a series of tests, divided by the mean of the RM tests or the applicable emission limit.

3.10 *Sample Interface* means that portion of the CEMS used for one or more of the following: sample acquisition, sample delivery, sample conditioning, or protection of the monitor from the effects of the stack effluent.

3.11 *Span Value* means the calibration portion of the measurement range as specified in the applicable regulation or other requirement. If the span is not specified in the applicable regulation or other requirement, then it must be a value approximately equivalent to two times the emission standard. For spans less than 500 ppm, the span value may either be rounded upward to the next highest multiple of 10 ppm, or to the next highest multiple of 100 ppm such that the equivalent emission concentration is not less than 30 percent of the selected span value.

4.0 Interferences [Reserved]

5.0 Safety

The procedures required under this performance specification may involve hazardous materials, operations, and equipment. This performance specification may not address all of the safety problems associated with these procedures. It is the responsibility of the user to establish appropriate safety and health practices and determine the applicable regulatory limitations prior to performing these procedures. The CEMS user's manual and materials recommended by the reference method should be consulted for specific precautions to be taken.

6.0 Equipment and Supplies

6.1 CEMS Equipment Specifications.

6.1.1 Data Recorder. The portion of the CEMS that provides a record of analyzer output. The data recorder may record other pertinent data such as effluent flow rates, various instrument temperatures or abnormal CEMS operation. The data recorder output range must include the full range of expected concentration values in the gas stream to be sampled including zero and span values.

6.1.2 The CEMS design should also allow the determination of calibration drift at the zero and span values. If this is not possible or practical, the design must allow these determinations to be conducted at a low-level value (zero to 20 percent of the span value) and at a value between 50 and 100 percent of the span value. In special cases, the Administrator may approve a single-point calibration drift determination.

6.2 Other equipment and supplies, as needed by the applicable reference method(s) (see section 8.4.2 of this Performance Specification), may be required.

7.0 Reagents and Standards

7.1 Reference Gases, Gas Cells, or Optical Filters. As specified by the CEMS manufacturer for calibration of the CEMS (these need not be certified).

7.2 Reagents and Standards. May be required as needed by the applicable reference method(s) (see section 8.4.2 of this Performance Specification).

8.0 Performance Specification Test Procedure

8.1 Installation and Measurement Location Specifications.

8.1.1 CEMS Installation. Install the CEMS at an accessible location where the pollutant concentration or emission rate measurements are directly representative or can be corrected so as to be representative of the total emissions from the affected facility or at the measurement location cross section. Then select representative measurement points or paths for monitoring in locations that the CEMS will pass the RA test (see section 8.4). If the cause of failure to meet the RA test is determined to be the measurement location and a satisfactory correction technique cannot be established, the Administrator may require the CEMS to be relocated. Suggested measurement locations and points or paths that are most likely to provide data that will meet the RA requirements are listed below.

8.1.2 CEMS Measurement Location. It is suggested that the measurement location be (1) at least two equivalent diameters downstream from the nearest control device, the point of pollutant generation, or other point at which a change in the pollutant concentration or emission rate may occur and (2) at least a half equivalent diameter upstream from the effluent exhaust or control device.

8.1.2.1 Point CEMS. It is suggested that the measurement point be (1) no less than 1.0 meter (3.3 ft) from the stack or duct wall or (2) within or centrally located over the centroidal area of the stack or duct cross section.

8.1.2.2 Path CEMS. It is suggested that the effective measurement path (1) be totally within the inner area bounded by a line 1.0 meter (3.3 ft) from the stack or duct wall, or (2) have at least 70 percent of the path within the inner 50 percent of the stack or duct cross-sectional area, or (3) be centrally located over any part of the centroidal area.

8.1.3 Reference Method Measurement Location and Traverse Points.

8.1.3.1 Select, as appropriate, an accessible RM measurement point at least two equivalent diameters downstream from the nearest control device, the point of pollutant generation, or other point at which a change in the pollutant concentration or emission rate may occur, and at least a half equivalent diameter upstream from the effluent exhaust or control device. When pollutant concentration changes are due solely to diluent leakage (*e.g.,* air heater leakages) and pollutants and diluents are simultaneously measured at the same location, a half diameter may be used in lieu of two equivalent diameters. The CEMS and RM locations need not be the same.

8.1.3.2 Select traverse points that assure acquisition of representative samples over the stack or duct cross section. The minimum requirements are as follows: Establish a "measurement line" that passes through the centroidal area and in the direction of any expected stratification. If this line interferes with the CEMS measurements, displace the line up to 30 cm (12 in.) (or 5 percent of the equivalent diameter of the cross section, whichever is less) from the centroidal area. Locate three traverse points at 16.7, 50.0, and 83.3 percent of the measurement line. If the measurement line is longer than 2.4 meters (7.8 ft) and pollutant stratification is not expected, the three traverse points may be located on the line at 0.4, 1.2, and 2.0 meters from the stack or duct wall. This option must not be used after wet scrubbers or at points where two streams with different pollutant concentrations are combined. If stratification is suspected, the following procedure is suggested. For rectangular ducts, locate at least nine sample points in the cross section such that sample points are the centroids of similarly-shaped, equal area divisions of the cross section. Measure the pollutant concentration, and, if applicable, the diluent concentration at each point using appropriate reference methods or other appropriate instrument methods that give responses relative to pollutant concentrations. Then calculate the mean value for all sample points. For circular ducts, conduct a 12-point traverse (*i.e.,* six points on each of the two perpendicular diameters) locating the sample points as described in 40 CFR 60, Appendix A, Method 1. Perform the measurements and calculations as described above. Determine if the mean pollutant concentration is more than 10% different from any single point. If so, the cross section is considered to be stratified, and the tester may not use the alternative traverse point locations (...0.4, 1.2, and 2.0 meters from the stack or duct wall.) but must use the three traverse points at 16.7, 50.0, and 83.3 percent of the entire measurement line. Other traverse points may be selected, provided that they can be shown to the satisfaction of the Administrator to provide a representative sample over the stack or duct cross section. Conduct all necessary RM tests within 3 cm (1.2 in.) of the traverse points, but no closer than 3 cm (1.2 in.) to the stack or duct wall.

8.2 Pretest Preparation. Install the CEMS, prepare the RM test site according to the specifications in section 8.1, and prepare the CEMS for operation according to the manufacturer's written instructions.

8.3 Calibration Drift Test Procedure.

8.3.1 *CD Test Period.* While the affected facility is operating, determine the magnitude of the CD once each day (at 24-hour intervals) for 7 consecutive calendar days according to the procedure given in sections 8.3.2 through 8.3.4. Alternatively, the CD test may be conducted over 7 consecutive unit operating days.

8.3.2 The purpose of the CD measurement is to verify the ability of the CEMS to conform to the established CEMS calibration used for determining the emission concentration or emission rate. Therefore, if periodic automatic or manual adjustments are made to the CEMS zero and calibration settings, conduct the CD test immediately before these adjustments, or conduct it in such a way that the CD can be determined.

8.3.3 Conduct the CD test at the two points specified in section 6.1.2. Introduce to the CEMS the reference gases, gas cells, or optical filters (these need not be certified). Record the CEMS response and subtract this value from the reference value (see example data sheet in Figure 2-1).

8.4 Relative Accuracy Test Procedure.

8.4.1 RA Test Period. Conduct the RA test according to the procedure given in sections 8.4.2 through 8.4.6 while the affected facility is operating at more than 50 percent of normal load, or as specified in an applicable subpart. The RA test may be conducted during the CD test period.

8.4.2 Reference Methods. Unless otherwise specified in an applicable subpart of the regulations, Methods 3B, 4, 6, and 7, or their approved alternatives, are the reference methods for diluent (O_2 and CO_2), moisture, SO_2, and NO_X, respectively.

8.4.3 Sampling Strategy for RM Tests. Conduct the RM tests in such a way that they will yield results representative of the emissions from the source and can be correlated to the CEMS data. It is preferable to conduct the diluent (if applicable), moisture (if needed), and pollutant measurements simultaneously. However, diluent and moisture measurements that are taken within an hour of the pollutant measurements may be used to calculate dry pollutant concentration and emission rates. In order to correlate the CEMS and RM data properly, note the beginning and end of each RM test period of each run (including the exact time of day) on the CEMS chart recordings or other permanent record of output. Use the following strategies for the RM tests:

8.4.3.1 For integrated samples (*e.g.,* Methods 6 and Method 4), make a sample traverse of at least 21 minutes, sampling for an equal time at each traverse point (see section 8.1.3.2 for discussion of traverse points.

8.4.3.2 For grab samples (*e.g.,* Method 7), take one sample at each traverse point, scheduling the grab samples so that they are taken simultaneously (within a 3-minute period) or at an equal interval of time apart over the span of time the CEM pollutant is measured. A test run for grab samples must be made up of at least three separate measurements.

NOTE: At times, CEMS RA tests are conducted during new source performance standards performance tests. In these cases, RM results obtained during CEMS RA tests may be used to determine compliance as long as the source and test conditions are consistent with the applicable regulations.

8.4.4 Number of RM Tests. Conduct a minimum of nine sets of all necessary RM test runs.

NOTE: More than nine sets of RM tests may be performed. If this option is chosen, a maximum of three sets of the test results may be rejected so long as the total number of test results used to determine the RA is greater than or equal to nine. However, all data must be reported, including the rejected data.

8.4.5 Correlation of RM and CEMS Data. Correlate the CEMS and the RM test data as to the time and duration by first determining from the CEMS final output (the one used for reporting) the integrated average pollutant concentration or emission rate for each pollutant RM test period. Consider system response time, if important, and confirm that the pair of results are on a consistent moisture, temperature, and diluent concentration basis. Then, compare each integrated CEMS value against the corresponding average RM value. Use the following guidelines to make these comparisons.

8.4.5.1 If the RM has an integrated sampling technique, make a direct comparison of the RM results and CEMS integrated average value.

8.4.5.2 If the RM has a grab sampling technique, first average the results from all grab samples taken during the test run, and then compare this average value against the integrated value obtained from the CEMS chart recording or output during the run. If the pollutant concentration is varying with time over the run, the arithmetic average of the CEMS value recorded at the time of each grab sample may be used.

8.4.6 Calculate the mean difference between the RM and CEMS values in the units of the emission standard, the standard deviation, the confidence coefficient, and the relative accuracy according to the procedures in section 12.0.

8.5 Reporting. At a minimum (check with the appropriate regional office, State, or Local agency for additional requirements, if any), summarize in tabular form the results of the CD tests and the RA tests or alternative RA procedure, as appropriate. Include all data sheets, calculations, charts (records of CEMS responses), cylinder gas concentration certifications, and calibration cell response certifications (if applicable) necessary to confirm that the performance of the CEMS met the performance specifications.

9.0 Quality Control [Reserved]

10.0 Calibration and Standardization [Reserved]

11.0 Analytical Procedure

Sample collection and analysis are concurrent for this Performance Specification (see section 8.0). Refer to the RM for specific analytical procedures.

12.0 Calculations and Data Analysis

Summarize the results on a data sheet similar to that shown in Figure 2-2 (in section 18.0).

12.1 All data from the RM and CEMS must be on a consistent dry basis and, as applicable, on a consistent diluent basis and in the units of the emission standard. Correct the RM and CEMS data for moisture and diluent as follows:

12.1.1 Moisture Correction (as applicable). Correct each wet RM run for moisture with the corresponding Method 4 data; correct each wet CEMS run using the corresponding CEMS moisture monitor date using Equation 2-1.

$$\text{Concentration}_{(\text{dry})} = \frac{Concentration_{wet}}{(1 - B_{ws})} \qquad \text{Eq. 2-1}$$

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12.1.2 Correction to Units of Standard (as applicable). Correct each dry RM run to the units of the emission standard with the corresponding Method 3B data; correct each dry CEMS run using the corresponding CEMS diluent monitor data as follows:

12.1.2.1 Correct to Diluent Basis. The following is an example of concentration (ppm) correction to 7% oxygen.

$$ppm_{(corr)} = ppm_{(uncorr)}\left[\frac{20.9-7.0}{20.9-\%O_{2(dry)}}\right] \quad \text{Eq. 2-2}$$

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The following is an example of mass/gross calorific value (lbs/million Btu) correction.

lbs/MMBtu = $Conc_{(dry)}$ (F-factor) (20.9/20.9-%0_2)

12.2 Arithmetic Mean. Calculate the arithmetic mean of the difference, d, of a data set as follows:

$$\bar{d} = \frac{1}{n}\sum_{i=1}^{n} d_i \quad \text{Eq. 2-3}$$

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Where:

n = Number of data points.

$\sum_{i=1}^{n} d_i$ = Algebraic summation of the individual differences d_i.

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12.3 Standard Deviation. Calculate the standard deviation, S_d, as follows:

$$S_d = \left[\frac{\sum_{i=1}^{n} d_i^2 - \frac{\left[\sum_{i=1}^{n} d_i\right]^2}{n}}{n-1}\right]^{\frac{1}{2}} \quad Eq.\ 2\text{-}4$$

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12.4 Confidence Coefficient. Calculate the 2.5 percent error confidence coefficient (one-tailed), CC, as follows:

$$CC = t_{0.975}\frac{S_d}{\sqrt{n}} \quad Eq.\ 2\text{-}5$$

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Where:

$t_{0.975}$ = t-value (see Table 2-1).

12.5 Relative Accuracy. Calculate the RA of a set of data as follows:

$$RA = \frac{\left[|\bar{d}| + |CC|\right]}{\overline{RM}} \times 100 \quad Eq.\ 2\text{-}6$$

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Where:

$|\bar{d}|$ = Absolute value of the mean differences (from Equation 2-3).

|CC| = Absolute value of the confidence coefficient (from Equation 2-3).

$\overline{RM}$ = Average RM value. In cases where the average emissions for the test are less than 50 percent of the applicable standard, substitute the emission standard value in the denominator of Eq. 2-6 in place of $\overline{RM}$. In all other cases, use $\overline{RM}$.

13.0 Method Performance

13.1 Calibration Drift Performance Specification. The CEMS calibration must not drift or deviate from the reference value of the gas cylinder, gas cell, or optical filter by more than 2.5 percent of the span value. If the CEMS includes pollutant and diluent monitors, the CD must be determined separately for each in terms of concentrations (See Performance Specification 3 for the diluent specifications), and none of the CDs may exceed the specification.

13.2 Relative Accuracy Performance Specification.

	Calculate . . .	**RA criteria (%)**
If average emissions during the RATA are ≥50% of emission standard	Use Eq. 2-6, with RM in the denominator	≤20.0
If average emissions during the RATA are <50% of emission standard	Use Eq. 2-6, emission standard in the denominator	≤10.0
For SO_2 emission standards ≤130 but ≥86 ng/J (0.30 and 0.20 lb/million Btu)	Use Eq. 2-6, emission standard in the denominator	≤15.0
For SO_2 emission standards <86 ng/J (0.20 lb/million Btu)	Use Eq. 2-6, emission standard in the denominator	≤20.0

13.3 For instruments that use common components to measure more than one effluent gas constituent, all channels must simultaneously pass the RA requirement, unless it can be demonstrated that any adjustments made to one channel did not affect the others.

14.0 Pollution Prevention [Reserved]

15.0 Waste Management [Reserved]

16.0 Alternative Procedures

Paragraphs 60.13(j)(1) and (2) of 40 CFR part 60 contain criteria for which the reference method procedure for determining relative accuracy (see section 8.4 of this Performance Specification) may be waived and the following procedure substituted.

16.1 Conduct a complete CEMS status check following the manufacturer's written instructions. The check should include operation of the light source, signal receiver, timing mechanism functions, data acquisition and data reduction functions, data recorders, mechanically operated functions (mirror movements, zero pipe operation, calibration gas valve operations, etc.), sample filters, sample line heaters, moisture traps, and other related functions of the CEMS, as applicable. All parts of the CEMS shall be functioning properly before proceeding to the alternative RA procedure.

16.2 Alternative RA Procedure.

16.2.1 Challenge each monitor (both pollutant and diluent, if applicable) with cylinder gases of known concentrations or calibration cells that produce known responses at two measurement points within the ranges shown in Table 2-2 (Section 18).

16.2.2 Use a separate cylinder gas (for point CEMS only) or calibration cell (for path CEMS or where compressed gas cylinders can not be used) for measurement points 1 and 2. Challenge the CEMS and record the responses three times at each measurement point. The Administrator may allow dilution of cylinder gas using the performance criteria in Test Method 205, 40 CFR Part 51, Appendix M. Use the average of the three responses in determining relative accuracy.

16.2.3 Operate each monitor in its normal sampling mode as nearly as possible. When using cylinder gases, pass the cylinder gas through all filters, scrubbers, conditioners, and other monitor components used during normal sampling and as much of the sampling probe as practical. When using calibration cells, the CEMS components used in the normal sampling mode should not be by-passed during the RA determination. These include light sources, lenses, detectors, and reference cells. The CEMS should be challenged at each measurement point for a sufficient period of time to assure adsorption-desorption reactions on the CEMS surfaces have stabilized.

16.2.4 Use cylinder gases that have been certified by comparison to National Institute of Standards and Technology (NIST) gaseous standard reference material (SRM) or NIST/EPA approved gas manufacturer's certified reference material (CRM) (See Reference 2 in section 17.0) following EPA Traceability Protocol Number 1 (See Reference 3 in section 17.0). As an alternative to Protocol Number 1 gases, CRM's may be used directly as alternative RA cylinder gases. A list of gas manufacturers that have prepared approved CRM's is available from EPA at the address shown in Reference 2. Procedures for preparation of CRM's are described in Reference 2.

16.2.5 Use calibration cells certified by the manufacturer to produce a known response in the CEMS. The cell certification procedure shall include determination of CEMS response produced by the calibration cell in direct comparison with measurement of gases of known concentration. This can be accomplished using SRM or CRM gases in a laboratory source simulator or through extended tests using reference methods at the CEMS location in the exhaust stack. These procedures are discussed in Reference 4 in section 17.0. The calibration cell certification procedure is subject to approval of the Administrator.

16.3 The differences between the known concentrations of the cylinder gases and the concentrations indicated by the CEMS are used to assess the accuracy of the CEMS. The calculations and limits of acceptable relative accuracy are as follows:

16.3.1 For pollutant CEMS:

$$RA = \left| \left(\frac{\bar{d}}{AC} \right) 100 \right| \leq 15 \text{ percent} \qquad \text{Eq. 2-7}$$

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Where:

$\bar{d}$ = Average difference between responses and the concentration/responses (see section 16.2.2).

AC = The known concentration/response of the cylinder gas or calibration cell.

16.3.2 For diluent CEMS:

$RA=\bar{d}$; ≤0.7 percent O_2 or CO_2, as applicable.

NOTE: Waiver of the relative accuracy test in favor of the alternative RA procedure does not preclude the requirements to complete the CD tests nor any other requirements specified in an applicable subpart for reporting CEMS data and performing CEMS drift checks or audits.

17.0 References

1. Department of Commerce. Experimental Statistics. Handbook 91. Washington, D.C. p. 3-31, paragraphs 3-3.1.4.

2. "A Procedure for Establishing Traceability of Gas Mixtures to Certain National Bureau of Standards Standard Reference Materials." Joint publication by NBS and EPA. EPA 600/7-81-010. Available from U.S. Environmental Protection Agency, Quality Assurance Division (MD-77), Research Triangle Park, North Carolina 27711.

3. "Traceability Protocol for Establishing True Concentrations of Gases Used for Calibration and Audits of Continuous Source Emission Monitors. (Protocol Number 1)." June 1978. Protocol Number 1 is included in the Quality Assurance Handbook for Air Pollution Measurement Systems, Volume III, Stationary Source Specific Methods. EPA-600/4-77-027b. August 1977.

4. "Gaseous Continuous Emission Monitoring Systems—Performance Specification Guidelines for SO_2, NO_X, CO_2, O_2, and TRS." EPA-450/3-82-026. Available from the U.S. EPA, Emission Measurement Center, Emission Monitoring and Data Analysis Division (MD-19), Research Triangle Park, North Carolina 27711.

18.0 Tables, Diagrams, Flowcharts, and Validation Data

TABLE 2-1—t-VALUES

n[a]	$t_{0.975}$	n[a]	$t_{0.975}$	n[a]	$t_{0.975}$
2	12.706	7	2.447	12	2.201
3	4.303	8	2.365	13	2.179
4	3.182	9	2.306	14	2.160
5	2.776	10	2.262	15	2.145
6	2.571	11	2.228	16	2.131

[a] The values in this table are already corrected for n−1 degrees of freedom. Use n equal to the number of individual values.

TABLE 2-2—MEASUREMENT RANGE

Measurement point	Pollutant monitor	Diluent monitor for	
		CO_2	O_2
1	20-30% of span value	5-8% by volume	4-6% by volume.
2	50-60% of span value	10-14% by volume	8-12% by volume.

Figure 2-1. Calibration Drift Determination

	Day	Date and time	Calibration value (C)	Monitor value (M)	Difference (C-M)	Percent of span value (C-M)/span value × 100
Low-level						
High-level						

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FIGURE 2-2. RELATIVE ACCURACY DETERMINATION.

Run No.	Date and time	SO_2			NO_x[b]			CO_2 or O_2[a]		SO_2[a]			NO_x[a]		
		RM	CEMS	Diff	RM	CEMS	Diff	RM	CEMS	RM	CEMS	Diff	RM	CEMS	Diff
		ppm[c]			ppm[c]			%[c]	%[c]	mass/GCV			mass/GCV		
1															
2															
3															
4															
5															
6															
7															
8															
9															
10															
11															
12															
Average															
Confidence Interval															
Accuracy															

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[a]For Steam generators.

[b]Average of three samples.

[c]Make sure that RM and CEMS data are on a consistent basis, either wet or dry.

Performance Specification 16—Specifications and Test Procedures for Predictive Emission Monitoring Systems in Stationary Sources

1.0 Scope and Application

1.1 *Does this performance specification apply to me?* If you, the source owner or operator, intend to use (with any necessary approvals) a predictive emission monitoring system (PEMS) to show compliance with your emission limitation under 40 CFR 60, 61, or 63, you must use the procedures in this performance specification (PS) to determine whether your PEMS is acceptable for use in demonstrating compliance with applicable requirements. Use these procedures to certify your PEMS after initial installation and periodically thereafter to ensure the PEMS is operating properly. If your PEMS contains a diluent (O_2 or CO_2) measuring component and your emissions limitation is in units that require a diluent measurement (*e.g.* lbs/mm Btu), the diluent component must be tested as well. These specifications apply to PEMS that are installed under 40 CFR 60, 61, and 63 after the effective date of this performance specification. These specifications do not apply to parametric monitoring systems, these are covered under PS-17.

1.1.1 *How do I certify my PEMS after it is installed?* PEMS must pass a relative accuracy (RA) test and accompanying statistical tests in the initial certification test to be acceptable for use in demonstrating compliance with applicable requirements. Ongoing quality assurance tests also must be conducted to ensure the PEMS is operating properly. An ongoing sensor evaluation procedure must be in place before the PEMS certification is complete. The amount of testing and data validation that is required depends upon the regulatory needs, *i.e.*, whether precise quantification of emissions will be needed or whether indication of exceedances of some regulatory threshold will suffice. Performance criteria are more rigorous for PEMS used in determining continual compliance with an emission limit than those used to measure excess emissions. You must perform the initial certification test on your PEMS before reporting any PEMS data as quality-assured.

1.1.2 *Is other testing required after certification?* After you initially certify your PEMS, you must pass additional periodic performance checks to ensure the long-term quality of data. These periodic checks are listed in the table in section 9. You are always responsible for properly maintaining and operating your PEMS.

2.0 Summary of Performance Specification

The following performance tests are required in addition to other equipment and measurement location requirements.

2.1 Initial PEMS Certification.

2.1.1 Excess Emissions PEMS. For a PEMS that is used for excess emission reporting, the owner or operator must perform a minimum 9-run, 3-level (3 runs at each level) RA test (see section 8.2).

2.1.2 Compliance PEMS. For a PEMS that is used for continual compliance standards, the owner or operator must perform a minimum 27-run, 3-level (9 runs at each level) RA test (see section 8.2). Additionally, the data must be evaluated for bias and by F-test and correlation analysis.

2.2 Periodic Quality Assurance (QA) Assessments. Owners and operators of all PEMS are required to conduct quarterly relative accuracy audits (RAA) and yearly relative accuracy test audits (RATA) to assess ongoing PEMS operation. The frequency of these periodic assessments may be shortened by successful operation during a prior year.

3.0 Definitions

The following definitions apply:

3.1 *Centroidal Area* means that area in the center of the stack (or duct) comprising no more than 1 percent of the stack cross-sectional area and having the same geometric shape as the stack.

3.2 *Data Recorder* means the equipment that provides a permanent record of the PEMS output. The data recorder may include automatic data reduction capabilities and may include electronic data records, paper records, or a combination of electronic data and paper records.

3.3 *Defective sensor* means a sensor that is responsible for PEMS malfunction or that operates outside the approved operating envelope. A defective sensor may be functioning properly, but because it is operating outside the approved operating envelope, the resulting predicted emission is not validated.

3.4 *Diluent PEMS* means the total equipment required to predict a diluent gas concentration or emission rate.

3.5 *Operating envelope* means the defined range of a parameter input that is established during PEMS development. Emission data generated from parameter inputs that are beyond the operating envelope are not considered quality assured and are therefore unacceptable.

3.6 *PEMS* means all of the equipment required to predict an emission concentration or emission rate. The system may consist of any of the following major subsystems: sensors and sensor interfaces, emission model, algorithm, or equation that uses process data to generate an output that is proportional to the emission concentration or emission rate, diluent emission model, data recorder, and sensor evaluation system. Systems that use fewer than 3 variables do not qualify as PEMS unless the system has been specifically approved by the Administrator for use as a PEMS. A PEMS may predict emissions data that are corrected for diluent if the relative accuracy and relevant QA tests are passed in the emission units corrected for diluent. Parametric monitoring systems that serve as indicators of compliance and have *parametric* limits but do not predict emissions to comply with an *emissions* limit are not included in this definition.

3.7 *PEMS training* means the process of developing or confirming the operation of the PEMS against a reference method under specified conditions.

3.8 *Quarter* means a quarter of a calendar year in which there are at least 168 unit operating hours.

3.9 *Reconciled Process Data* means substitute data that are generated by a sensor evaluation system to replace that of a failed sensor. Reconciled process data may not be used without approval from the Administrator.

3.10 *Relative Accuracy* means the accuracy of the PEMS when compared to a reference method (RM) at the source. The RA is the average difference between the pollutant PEMS and RM data for a specified number of comparison runs plus a 2.5 percent confidence coefficient, divided by the average of the RM tests. For a diluent PEMS, the RA may be expressed as a percentage of absolute difference between the PEMS and RM. Alternative specifications are given for units that have very low emissions.

3.11 *Relative Accuracy Audit* means a quarterly audit of the PEMS against a portable analyzer meeting the requirements of ASTM D6522-00 or a RM for a specified number of runs. A RM may be used in place of the portable analyzer for the RAA.

3.12 *Relative Accuracy Test Audit* means a RA test that is performed at least once every four calendar quarters after the initial certification test while the PEMS is operating at the normal operating level.

3.13 *Reference Value* means a PEMS baseline value that may be established by RM testing under conditions when all sensors are functioning properly. This reference value may then be used in the sensor evaluation system or in adjusting new sensors.

3.14 *Sensor Evaluation System* means the equipment or procedure used to periodically assess the quality of sensor input data. This system may be a sub-model that periodically cross-checks sensor inputs among themselves or any other procedure that checks sensor integrity at least daily (when operated for more than one hour in any calendar day).

3.15 *Sensors and Sensor Interface* means the equipment that measures the process input signals and transports them to the emission prediction system.

4.0 Interferences [Reserved]

5.0 Safety [Reserved]

6.0 Equipment and Supplies

6.1 PEMS Design. You must detail the design of your PEMS and make this available in reports and for on-site inspection. You must also establish the following, as applicable:

6.1.1 Number of Input Parameters. An acceptable PEMS will normally use three or more input parameters. You must obtain the Administrator's permission on a case-by-case basis if you desire to use a PEMS having fewer than three input parameters.

6.1.2 Parameter Operating Envelopes. Before you evaluate your PEMS through the certification test, you must specify the input parameters your PEMS uses, define their range of minimum and maximum values (operating envelope), and demonstrate the integrity of the parameter operating envelope using graphs and data from the PEMS development process, vendor information, or engineering calculations, as appropriate. If you operate the PEMS beyond these envelopes at any time after the certification test, the data generated during this condition will not be acceptable for use in demonstrating compliance with applicable requirements. If these parameter operating envelopes are not clearly defined and supported by development data, the PEMS operation will be limited to the range of parameter inputs encountered during the certification test until the PEMS has a new operating envelope established.

6.1.3 Source-Specific Operating Conditions. Identify any source-specific operating conditions, such as fuel type, that affect the output of your PEMS. You may only use the PEMS under the source-specific operating conditions it was certified for.

6.1.4 Ambient Conditions. You must explain whether and how ambient conditions and seasonal changes affect your PEMS. Some parameters such as absolute ambient humidity cannot be manipulated during a test. The effect of ambient conditions such as humidity on the pollutant concentration must be determined and this effect extrapolated to include future anticipated conditions. Seasonal changes and their effects on the PEMS must be evaluated unless you can show that such effects are negligible.

6.1.5 PEMS Principle of Operation. If your PEMS is developed on the basis of known physical principles, you must identify the specific physical assumptions or mathematical manipulations that support its operation. If your PEMS is developed on the basis of linear or nonlinear regression analysis, you must make available the paired data (preferably in graphic form) used to develop or train the model.

6.1.6 Data Recorder Scale. If you are not using a digital recorder, you must choose a recorder scale that accurately captures the desired range of potential emissions. The lower limit of your data recorder's range must be no greater than 20 percent of the applicable emission standard (if subject to an emission standard). The upper limit of your data recorder's range must be determined using the following table. If you obtain approval first, you may use other lower and upper recorder limits.

If PEMS is measuring. . .	And if. . .	Then your upper limit. . .
Uncontrolled emissions, such as NO_X at the stack of a natural gas-fired boiler	No other regulation sets an upper limit for the data recorder's range	Must be 1.25 to 2 times the average potential emission level
Uncontrolled emissions, such as NO_X at the stack of a natural gas-fired boiler	Another regulation sets an upper limit for the data recorder's range	Must follow the other regulation
Controlled emissions	Must be 1.5 to 2.0 times concentration of the emission standard that applies to your emission unit	
Continual compliance emissions for an applicable regulation	Must be 1.1 to 1.5 times the concentration of the emission standard that applies to your emission unit	

6.1.7 Sensor Location and Repair. We recommend you install sensors in an accessible location in order to perform repairs and replacements. Permanently-installed platforms or ladders may not be needed. If you install sensors in an area that is not accessible, you may be required to shut down the emissions unit to repair or replace a sensor. Conduct a new RATA after replacing a sensor that supplies a critical PEMS parameter if the new sensor provides a different output or scaling or changes the historical training dataset of the PEMS. Replacement of a non-critical sensor that does not cause an impact in the accuracy of the PEMS does not trigger a RATA. All sensors must be calibrated as often as needed but at least as often as recommended by the manufacturers.

6.1.8 Sensor Evaluation System. Your PEMS must be designed to perform automatic or manual determination of defective sensors on at least a daily basis. This sensor evaluation system may consist of a sensor validation sub-model, a comparison of redundant sensors, a spot check of sensor input readings at a reference value, operation, or emission level, or other procedure that detects faulty or failed sensors. Some sensor evaluation systems generate substitute values (reconciled data) that are used when a sensor is perceived to have failed. You must obtain prior approval before using reconciled data.

6.1.9 Parameter Envelope Exceedances. Your PEMS must include a plan to detect and notify the operator of parameter envelope exceedances. Emission data collected outside the ranges of the sensor envelopes will not be considered quality assured.

6.2 Recordkeeping. All valid data recorded by the PEMS must be used to calculate the emission value.

7.0 Reagents and Standards [Reserved]

8.0 Sample Collection, Preservation, Storage, and Transport

8.1 Initial Certification. Use the following procedure to certify your PEMS. Complete all PEMS training before the certification begins.

8.2 Relative Accuracy Test.

8.2.1 Reference Methods. Unless otherwise specified in the applicable regulations, you must use the test methods in appendix A of this part for the RM test. Conduct the RM tests at three operating levels. The RM tests shall be performed at a low-load (or production) level between the minimum safe, stable load and 50 percent of the maximum level load, at the mid-load level (an intermediary level between the low and high levels), and at a high-load level between 80 percent and the maximum load. Alternatively, if practicable, you may test at three levels of the key operating parameter (e.g. selected based on a covariance analysis between each parameter and the PEMS output) equally spaced within the normal range of the parameter.

8.2.2 Number of RM Tests for Excess Emission PEMS. For PEMS used for excess emission reporting, conduct at least the following number of RM tests at the following key parameter operating levels:

(1) Three at a low level.

(2) Three at a mid level.

(3) Three at a high level.

You may choose to perform more than nine total RM tests. If you perform more than nine tests, you may reject a maximum of three tests as long as the total number of test results used to determine the RA is nine or greater and each operating level has at least three tests. You must report all data, including the rejected data.

8.2.3 Number of RM Tests for Continual Compliance PEMS. For PEMS used to determine compliance, conduct at least the following number of RM tests at the following key parameter operating levels:

(1) Nine at a low level.

(2) Nine at a mid level.

(3) Nine at a high level.

You may choose to perform more than 9 RM runs at each operating level. If you perform more than 9 runs, you may reject a maximum of three runs per level as long as the total number of runs used to determine the RA at each operating level is 9 or greater.

8.2.4 Reference Method Measurement Location. Select an accessible measurement point for the RM that will ensure you measure emissions representatively. Ensure the location is at least two equivalent stack diameters downstream and half an equivalent diameter upstream from the nearest flow disturbance such as the control device, point of pollutant generation, or other place where the pollutant concentration or emission rate can change. You may use a half diameter downstream instead of the two diameters if you meet both of the following conditions:

(1) Changes in the pollutant concentration are caused solely by diluent leakage, such as leaks from air heaters.

(2) You measure pollutants and diluents simultaneously at the same locations.

8.2.5 Traverse Points. Select traverse points that ensure representative samples. Conduct all RM tests within 3 cm of each selected traverse point but no closer than 3 cm to the stack or duct wall. The minimum requirement for traverse points are as follows:

(1) Establish a measurement line across the stack that passes through the center and in the direction of any expected stratification.

(2) Locate a minimum of three traverse points on the line at 16.7, 50.0, and 83.3 percent of the stack inside diameter.

(3) Alternatively, if the stack inside diameter is greater than 2.4 meters, you may locate the three traverse points on the line at 0.4, 1.2, and 2.0 meters from the stack or duct wall. You may not use this alternative option after wet scrubbers or at points where two streams with different pollutant concentrations are combined. You may select different traverse points if you demonstrate and provide verification that it provides a representative sample. You may also use the traverse point specifications given the RM.

8.2.6 Relative Accuracy Procedure. Perform the number of RA tests at the levels required in sections 8.2.2 and 8.2.3. For integrated samples (*e.g.*, Method 3A or 7E), make a sample traverse of at least 21 minutes, sampling for 7 minutes at each traverse point. For grab samples (*e.g.*, Method 3 or 7), take one sample at each traverse point, scheduling the grab samples so that they are taken simultaneously (within a 3-minute period) or at an equal interval of time apart over a 21-minute period. A test run for grab samples must be made up of at least three separate measurements. Where multiple fuels are used in the monitored unit and the fuel type affects the predicted emissions, determine a RA for each fuel unless the effects of the alternative fuel on predicted emissions or diluent were addressed in the model training process. The unit may only use fuels that have been evaluated this way.

8.2.7 Correlation of RM and PEMS Data. Mark the beginning and end of each RM test run (including the exact time of day) on the permanent record of PEMS output. Correlate the PEMS and the RM test data by the time and duration using the following steps:

A. Determine the integrated pollutant concentration for the PEMS for each corresponding RM test period.

B. Consider system response time, if important, and confirm that the pair of results is on a consistent moisture, temperature, and diluent concentration basis.

C. Compare each average PEMS value to the corresponding average RM value. Use the following guidelines to make these comparisons.

If . . .	Then . . .	And then . . .
The RM has an instrumental or integrated non-instrumental sampling technique	Directly compare RM and PEMS results	
The RM has a grab sampling technique	Average the results from all grab samples taken during the test run. The test run must include ≥3 separate grab measurements	Compare this average RM result with the PEMS result obtained during the run.

Use the paired PEMS and RM data and the equations in section 12.2 to calculate the RA in the units of the applicable emission standard. For this 3-level RA test, calculate the RA at each operation level.

8.3 Statistical Tests for PEMS that are Used for Continual Compliance. In addition to the RA determination, evaluate the paired RA and PEMS data using the following statistical tests.

8.3.1 Bias Test. From the RA data taken at the mid-level, determine if a bias exists between the RM and PEMS. Use the equations in section 12.3.1.

8.3.2 F-test. Perform a separate F-test for the RA paired data from each operating level to determine if the RM and PEMS variances differ by more than might be expected from chance. Use the equations in section 12.3.2.

8.3.3 Correlation Analysis. Perform a correlation analysis using the RA paired data from all operating levels combined to determine how well the RM and PEMS correlate. Use the equations in section 12.3.3. The correlation is waived if the process cannot be varied to produce a concentration change sufficient for a successful correlation test because of its technical design. In such cases, should a subsequent RATA identify a variation in the RM measured values by more than 30 percent, the waiver will not apply, and a correlation analysis test must be performed at the next RATA.

8.4 Reporting. Summarize in tabular form the results of the RA and statistical tests. Include all data sheets, calculations, and charts (records of PEMS responses) necessary to verify that your PEMS meets the performance specifications. Include in the report the documentation used to establish your PEMS parameter envelopes.

8.5 Reevaluating Your PEMS After a Failed Test, Change in Operations, or Change in Critical PEMS Parameter. After initial certification, if your PEMS fails to pass a quarterly RAA or yearly RATA, or if changes occur or are made that could result in a significant change in the emission rate (*e.g.*, turbine aging, process modification, new process operating modes, or changes to emission controls), your PEMS must be recertified using the tests and procedures in section 8.1. For example, if you initially developed your PEMS for the emissions unit operating at 80-100 percent of its range, you would have performed the initial test under these conditions. Later, if you wanted to operate the emission unit at 50-100 percent of its range, you must conduct another RA test and statistical tests, as applicable, to verify that the new conditions of 50-100 percent of range are functional. These tests must demonstrate that your PEMS provides acceptable data when operating in the new range or with the new critical PEMS parameter(s). The requirements of section 8.1 must be completed by the earlier of 60 unit operating days or 180 calendar days after the failed RATA or after the change that caused a significant change in emission rate.

9.0 Quality Control

You must incorporate a QA plan beyond the initial PEMS certification test to verify that your system is generating quality-assured data. The QA plan must include the components of this section.

9.1 QA/QC Summary. Conduct the applicable ongoing tests listed below.

Ongoing Quality Assurance Tests

Test	PEMS regulatory purpose	Acceptability	Frequency
Sensor Evaluation	All		Daily.
RAA	Compliance	3-test avg ≤10% of simultaneous analyzer or	Each quarter except quarter when RATA

		RM average	performed.
RATA	All	Same as for RA in Sec. 13.1	Yearly in quarter when RAA not performed.
Bias Correction	All	If $d_{avg} \leq \|cc\|$	Bias test passed (no correction factor needed).
PEMS Training	All	If $F_{critical} \geq F$ $r \geq 0.8$	Optional after initial and subsequent RATAs.
Sensor Evaluation Alert Test (optional)	All	See Section 6.1.8	After each PEMS training.

9.2 Daily Sensor Evaluation Check. Your sensor evaluation system must check the integrity of each PEMS input at least daily.

9.3 Quarterly Relative Accuracy Audits. In the first year of operation after the initial certification, perform a RAA consisting of at least three 30-minute portable analyzer or RM determinations each quarter a RATA is not performed. To conduct a RAA, follow the procedures in Section 8.2 for the relative accuracy test, except that only three sets of measurement data are required, and the statistical tests are not required. The average of the three or more portable analyzer or RM determinations must not exceed the limits given in Section 13.5. Report the data from all sets of measurement data. If a PEMS passes all quarterly RAAs in the first year and also passes the subsequent yearly RATA in the second year, you may elect to perform a single mid-year RAA in the second year in place of the quarterly RAAs. This option may be repeated, but only until the PEMS fails either a mid-year RAA or a yearly RATA. When such a failure occurs, you must resume quarterly RAAs in the quarter following the failure and continue conducting quarterly RAAs until the PEMS successfully passes both a year of quarterly RAAs and a subsequent RATA.

9.4 Yearly Relative Accuracy Test. Perform a minimum 9-run RATA at the normal operating level on a yearly basis in the quarter that the RAA is not performed. The statistical tests in Section 8.3 are not required for the yearly RATA.

10.0 Calibration and Standardization [Reserved]

11.0 Analytical Procedure [Reserved]

12.0 Calculations and Data Analysis

12.1 Nomenclature

B = PEMS bias adjustment factor.

cc = Confidence coefficient.

d_i = Difference between each RM and PEMS run.

$\bar{d}$ = Arithmetic mean of differences for all runs.

e_i = Individual measurement provided by the PEMS or RM at a particular level.

e_m = Mean of the PEMS or RM measurements at a particular level.

e_p = Individual measurement provided by the PEMS.

e_v = Individual measurement provided by the RM.

F = Calculated F-value.

n = Number of RM runs.

$PEMS_i$ = Individual measurement provided by the PEMS.

$PEMS_{iAdjusted}$ = Individual measurement provided by the PEMS adjusted for bias.

$\overline{PEMS}$ = Mean of the values provided by the PEMS at the normal operating range during the bias test.

r = Coefficient of correlation.

RA = Relative accuracy.

RAA = Relative accuracy audit.

$\overline{RM}$ = Average RM value (or in the case of the RAA, the average portable analyzer value). In cases where the average emissions for the test are less than 50 percent of the applicable standard, substitute the emission standard value here in place of the average RM value.

S_d = Standard deviation of differences.

S^2 = Variance of your PEMS or RM.

$t_{0.025}$ = t-value for a one-sided, 97.5 percent confidence interval (see Table 16-1).

12.2 Relative Accuracy Calculations. Calculate the mean of the RM values. Calculate the differences between the pairs of observations for the RM and the PEMS output sets. Finally, calculate the mean of the differences, standard deviation, confidence coefficient, and PEMS RA, using Equations 16-1, 16-2, 16-3, and 16-4, respectively. For compliance PEMS, calculate the RA at each test level. The PEMS must pass the RA criterion at each test level.

12.2.1 Arithmetic Mean. Calculate the arithmetic mean of the differences between paired RM and PEMS observations using Equation 16-1.

$$\bar{d} = \frac{1}{n}\sum_{i=1}^{n} d_i \qquad Eq.\ 16\text{-}1$$

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12.2.2 Standard Deviation. Calculate the standard deviation of the differences using Equation 16-2 (positive square root).

$$s_d = \sqrt{\frac{\sum_{i=1}^{n} d_i^2 - \frac{\left(\sum_{i=1}^{n} d_i\right)^2}{n}}{n-1}} \qquad Eq.\ 16\text{-}2$$

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12.2.3 Confidence Coefficient. Calculate the confidence coefficient using Equation 16-3 and Table 16-1 for n−1 degrees of freedom.

$$cc = t_{0.025}\frac{S_d}{\sqrt{n}} \qquad Eq.\ 16\text{-}3$$

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12.2.4 Relative Accuracy. Calculate the RA of your data using Equation 16-4.

$$RA = \frac{|\bar{d}| + |cc|}{\overline{RM}} \times 100 \qquad Eq.\ 16\text{-}4$$

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12.3 Compliance PEMS Statistical Tests. If your PEMS will be used for continual compliance purposes, conduct the following tests using the information obtained during the RA tests. For the pollutant measurements at any one test level, if the mean value of the RM is less than either 10 ppm or 5 percent of the emission standard, all statistical tests are waived at that specific test level. For diluent measurements at any one test level, if the mean value of the RM is less than 3 percent of span, all statistical tests are waived for that specific test level.

12.3.1 Bias Test. Conduct a bias test to determine if your PEMS is biased relative to the RM. Determine the PEMS bias by comparing the confidence coefficient obtained from Equation 16-3 to the arithmetic mean of the differences determined in Equation 16-1. If the arithmetic mean of the differences ($\bar{d}$) is greater than the absolute value of the confidence coefficient (cc), your PEMS must incorporate a bias factor to adjust future PEMS values as in Equation 16-5.

$$PEMS_{i\,Adjusted} = PEMS_i \times B \qquad Eq.\ 16\text{-}5$$

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Where:

$$B = 1 + \frac{|\bar{d}|}{\overline{PEMS}} \qquad Eq.\ 16\text{-}6a$$

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12.3.2 F-test. Conduct an F-test for each of the three RA data sets collected at different test levels. Calculate the variances of the PEMS and the RM using Equation 16-6.

$$S^2 = \frac{\sum_{i=1}^{n}(e_i - e_m)^2}{n-1} \qquad Eq.\ 16\text{-}6$$

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Determine if the variance of the PEMS data is significantly different from that of the RM data at each level by calculating the F-value using Equation 16-7.

$$F = \frac{S^2\ PEMS}{S^2 RM} \qquad Eq.\ 16\text{-}7$$

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Compare the calculated F-value with the critical value of F at the 95 percent confidence level with n-1 degrees of freedom. The critical value is obtained from Table 16-2 or a similar table for F-distribution. If the calculated F-value is greater than the critical value at any level, your proposed PEMS is unacceptable. For pollutant PEMS measurements, if the standard deviation of the RM is less than either 3 percent of the span or 5 ppm, use a RM standard deviation of either 5 ppm or 3 percent of span. For diluent PEMS measurements, if the standard deviation of the reference method is less than 3 percent of span, use a RM standard deviation of 3 percent of span.

12.3.3 Correlation Analysis. Calculate the correlation coefficient either manually using Eq. 16-8, on a graph, or by computer using all of the paired data points from all operating levels. Your PEMS correlation must be 0.8 or greater to be acceptable. If during the initial certification test, your PEMS data are determined to be auto-correlated according to the procedures in 40 CFR 75.41(b)(2), or if the signal-to-noise ratio of the data is less than 4, then the correlation analysis is permanently waived.

$$r = \frac{\sum epev - \left(\sum ep\right)\left(\sum ev\right)/n}{\sqrt{\left[\left(\sum ep^2 - \left(\sum ep\right)^2/n\right)\left(\sum ev^2 - \left(\sum ev\right)^2/n\right)\right]}} \qquad Eq.\ 16\text{-}8$$

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12.4 Relative Accuracy Audit. Calculate the quarterly RAA using Equation 16-9.

$$RAA = \frac{\overline{PEMS} - \overline{RM}}{\overline{RM}} x\,100 \qquad \text{Eq. 16-9}$$

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13.0 Method Performance

13.1 PEMS Relative Accuracy. The RA must not exceed 10 percent if the PEMS measurements are greater than 100 ppm or 0.2 lbs/mm Btu. The RA must not exceed 20 percent if the PEMS measurements are between 100 ppm (or 0.2 lb/mm Btu) and 10 ppm (or 0.05 lb/mm Btu). For measurements below 10 ppm, the absolute mean difference between the PEMS measurements and the RM measurements must not exceed 2 pppm. For diluent PEMS, an alternative criterion of ±1 percent absolute difference between the PEMS and RM may be used if less stringent.

13.2 PEMS Bias. Your PEMS data is considered biased and must be adjusted if the arithmetic mean (d) is greater than the absolute value of the confidence coefficient (cc) in Equations 16.1 and 16.3. In such cases, a bias factor must be used to correct your PEMS data.

13.3 PEMS Variance. Your calculated F-value must not be greater than the critical F-value at the 95-percent confidence level for your PEMS to be acceptable.

13.4 PEMS Correlation. Your calculated r-value must be greater than or equal to 0.8 for your PEMS to be acceptable.

13.5 Relative Accuracy Audits. The average of the three portable analyzer or RM determinations must not differ from the simultaneous PEMS average value by more than 10 percent of the analyzer or RM for concentrations greater than 100 ppm or 20 percent for concentrations between 100 and 20 ppm, or the test is failed. For measurements at 20 ppm or less, this difference must not exceed 2 ppm for a pollutant PEMS and 1 percent absolute for a diluents PEMS.

14.0 Pollution Prevention [Reserved]

15.0 Waste Management [Reserved]

16.0 References [Reserved]

17.0 Tables, Diagrams, Flowcharts, and Validation Data

TABLE 16-1—t-VALUES FOR ONE-SIDED, 97.5 PERCENT CONFIDENCE INTERVALS FOR SELECTED SAMPLE SIZES*

n−1*	t-value	n−1	t-value
1	12.706	15	2.131
2	4.303	16	2.120
3	3.182	17	2.110
4	2.776	18	2.101
5	2.571	19	2.093
6	2.447	20	2.086
7	2.365	21	2.080
8	2.306	22	2.074
9	2.262	23	2.069
10	2.228	24	2.064
11	2.201	25	2.060
12	2.179	26	2.056
13	2.160	27	2.052
14	2.145	>28	t-Table

*The value n is the number of RM runs; n−1 equals the degrees of freedom.

Table 16-2. F-Values for
Critical Value of F at the 95 Percent Confidence Level

d.f. for S^2_{RM}												d.f. for S^2_{PEMS}
	1	2	3	4	5	6	7	8	9	10	11	12
1	161.4	199.5	215.7	224.6	230.2	234.0	236.8	238.9	240.5	241.8	243.0	243.9
2	18.51	19.00	19.16	19.25	19.30	19.33	19.35	19.37	19.38	19.50	19.40	19.41
3	10.13	9.552	9.277	9.117	9.014	8.941	8.887	8.845	8.812	8.786	8.763	8.745
4	7.709	6.944	6.591	6.388	6.256	6.163	6.094	6.041	5.999	5.964	5.935	5.912
5	6.608	5.786	5.410	5.192	5.050	4.950	4.876	4.818	4.773	4.735	4.703	4.678
6	5.987	5.143	4.757	4.534	4.387	4.284	4.207	4.147	4.099	4.060	4.027	4.000
7	5.591	4.734	4.347	4.120	3.971	3.866	3.787	3.726	3.677	3.637	3.603	3.575
8	5.318	4.459	4.066	3.838	3.688	3.581	3.501	3.438	3.388	3.347	3.312	3.284
9	5.117	4.257	3.863	3.633	3.482	3.374	3.293	3.230	3.197	3.137	3.102	3.073
10	4.965	4.103	3.709	3.478	3.326	3.217	3.136	3.072	3.020	2.978	2.942	2.913
11	4.844	3.982	3.587	3.357	3.204	3.095	3.012	2.948	2.896	2.854	2.817	2.788
12	4.747	3.885	3.490	3.259	3.106	2.996	2.913	2.849	2.796	2.753	2.717	2.687

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Appendix F to Part 60—Quality Assurance Procedures

Procedure 1. Quality Assurance Requirements for Gas Continuous Emission Monitoring Systems Used for Compliance Determination

1. Applicability and Principle

1.1 Applicability. Procedure 1 is used to evaluate the effectiveness of quality control (QC) and quality assurance (QA) procedures and the quality of data produced by any continuous emission monitoring system (CEMS) that is used for determining compliance with the emission standards on a continuous basis as specified in the applicable regulation. The CEMS may include pollutant (e.g., $S0_2$ and $N0_x$) and diluent (e.g., 0_2 or $C0_2$) monitors.

This procedure specifies the minimum QA requirements necessary for the control and assessment of the quality of CEMS data submitted to the Environmental Protection Agency (EPA). Source owners and operators responsible for one or more CEMS's used for compliance monitoring must meet these minimum requirements and are encouraged to develop and implement a more extensive QA program or to continue such programs where they already exist.

Data collected as a result of QA and QC measures required in this procedure are to be submitted to the Agency. These data are to be used by both the Agency and the CEMS operator in assessing the effectiveness of the CEMS QC and QA procedures in the maintenance of acceptable CEMS operation and valid emission data.

Appendix F, Procedure 1 is applicable December 4, 1987. The first CEMS accuracy assessment shall be a relative accuracy test audit (RATA) (see section 5) and shall be completed by March 4, 1988 or the date of the initial performance test required by the applicable regulation, whichever is later.

1.2 Principle. The QA procedures consist of two distinct and equally important functions. One function is the assessment of the quality of the CEMS data by estimating accuracy. The other function is the control and improvement of the quality of the CEMS data by implementing QC policies and corrective actions. These two functions form a control loop: When the assessment function indicates that the data quality is inadequate, the control effort must be increased until the data quality is acceptable. In order to provide uniformity in the assessment and reporting of data quality, this procedure explicitly specifies the assessment methods for response drift and accuracy. The methods are based on procedures included in the applicable performance specifications (PS's) in appendix B of 40 CFR part 60. Procedure 1 also requires the analysis of the EPA audit samples concurrent with certain reference method (RM) analyses as specified in the applicable RM's.

Because the control and corrective action function encompasses a variety of policies, specifications, standards, and corrective measures, this procedure treats QC requirements in general terms to allow each source owner or operator to develop a QC system that is most effective and efficient for the circumstances.

2. Definitions

2.1 Continuous Emission Monitoring System. The total equipment required for the determination of a gas concentration or emission rate.

2.2 Diluent Gas. A major gaseous constituent in a gaseous pollutant mixture. For combustion sources, CO_2 and O_2 are the major gaseous constituents of interest.

2.3 Span Value. The upper limit of a gas concentration measurement range that is specified for affected source categories in the applicable subpart of the regulation.

2.4 Zero, Low-Level, and High-Level Values. The CEMS response values related to the source specific span value. Determination of zero, low-level, and high-level values is defined in the appropriate PS in appendix B of this part.

2.5 Calibration Drift (CD). The difference in the CEMS output reading from a reference value after a period of operation during which no unscheduled maintenance, repair or adjustment took place. The reference value may be supplied by a cylinder gas, gas cell, or optical filter and need not be certified.

2.6 Relative Accuracy (RA). The absolute mean difference between the gas concentration or emission rate determined by the CEMS and the value determined by the RM's plus the 2.5 percent error confidence coefficient of a series of tests divided by the mean of the RM tests or the applicable emission limit.

3. QC Requirements

Each source owner or operator must develop and implement a QC program. As a minimum, each QC program must include written procedures which should describe in detail, complete, step-by-step procedures and operations for each of the following activities:

1. Calibration of CEMS.

2. CD determination and adjustment of CEMS.

3. Preventive maintenance of CEMS (including spare parts inventory).

4. Data recording, calculations, and reporting.

5. Accuracy audit procedures including sampling and analysis methods.

6. Program of corrective action for malfunctioning CEMS.

As described in section 5.2, whenever excessive inaccuracies occur for two consecutive quarters, the source owner or operator must revise the current written procedures or modify or replace the CEMS to correct the deficiency causing the excessive inaccuracies.

These written procedures must be kept on record and available for inspection by the enforcement agency.

4. CD Assessment

4.1 CD Requirement. As described in 40 CFR 60.13(d), source owners and operators of CEMS must check, record, and quantify the CD at two concentration values at least once daily (approximately 24 hours) in accordance with the method prescribed by the manufacturer. The CEMS calibration must, as minimum, be adjusted whenever the daily zero (or low-level) CD or the daily high-level CD exceeds two times the limits of the applicable PS's in appendix B of this regulation.

4.2 Recording Requirement for Automatic CD Adjusting Monitors. Monitors that automatically adjust the data to the corrected calibration values (e.g., microprocessor control) must be programmed to record the unadjusted concentration measured in the CD prior to resetting the calibration, if performed, or record the amount of adjustment.

4.3 Criteria for Excessive CD. If either the zero (or low-level) or high-level CD result exceeds twice the applicable drift specification in appendix B for five, consecutive, daily periods, the CEMS is out-of-control. If either the zero (or low-level) or high-level CD result exceeds four times the applicable drift specification in appendix B during any CD check, the CEMS is out-of-control. If the CEMS is out-of-control, take necessary corrective action. Following corrective action, repeat the CD checks.

4.3.1 Out-Of-Control Period Definition. The beginning of the out-of-control period is the time corresponding to the completion of the fifth, consecutive, daily CD check with a CD in excess of two times the allowable limit, or the time corresponding to the completion of the daily CD check preceding the daily CD check that results in a CD in excess of four times the allowable limit. The end of the out-of-control period is the time corresponding to the completion of the CD check following corrective action that results in the CD's at both the zero (or low-level) and high-level measurement points being within the corresponding allowable CD limit (i.e., either two times or four times the allowable limit in appendix B).

4.3.2 CEMS Data Status During Out-of-Control Period. During the period the CEMS is out-of-control, the CEMS data may not be used in calculating emission compliance nor be counted towards meeting minimum data availability as required and described in the applicable subpart [e.g., §60.47a(f)].

4.4 Data Recording and Reporting. As required in §60.7(d) of this regulation (40 CFR part 60), all measurements from the CEMS must be retained on file by the source owner for at least 2 years. However, emission data obtained on each successive day while the CEMS is out-of-control may not be included as part of the minimum daily data requirement of the applicable subpart [e.g., §60.47a(f)] nor be used in the calculation of reported emissions for that period.

5. Data Accuracy Assessment

5.1 Auditing Requirements. Each CEMS must be audited at least once each calendar quarter. Successive quarterly audits shall occur no closer than 2 months. The audits shall be conducted as follows:

5.1.1 Relative Accuracy Test Audit (RATA). The RATA must be conducted at least once every four calendar quarters, except as otherwise noted in section 5.1.4 of this appendix. Conduct the RATA as described for the RA test procedure in the applicable PS in appendix B (e.g., PS 2 for SO_2 and NO_X). In addition, analyze the appropriate performance audit samples received from EPA as described in the applicable sampling methods (e.g., Methods 6 and 7).

5.1.2 Cylinder Gas Audit (CGA). If applicable, a CGA may be conducted in three of four calendar quarters, but in no more than three quarters in succession.

To conduct a CGA: (1) Challenge the CEMS (both pollutant and diluent portions of the CEMS, if applicable) with an audit gas of known concentration at two points within the following ranges:

Audit point	Audit range		
		Diluent monitors for—	
	Pollutant monitors	CO_2	O_2
1	20 to 30% of span value	5 to 8% by volume	4 to 6% by volume.
2	50 to 60% of span value	10 to 14% by volume	8 to 12% by volume.

Introduce each of the audit gases, three times each for a total of six challenges. Introduce the gases in such a manner that the entire CEMS is challenged. Do not introduce the same gas concentration twice in succession.

Use of separate audit gas cylinder for audit points 1 and 2. Do not dilute gas from audit cylinder when challenging the CEMS.

The monitor should be challenged at each audit point for a sufficient period of time to assure adsorption-desorption of the CEMS sample transport surfaces has stabilized.

(2) Operate each monitor in its normal sampling mode, i.e., pass the audit gas through all filters, scrubbers, conditioners, and other monitor components used during normal sampling, and as much of the sampling probe as is practical. At a minimum, the audit gas should be introduced at the connection between the probe and the sample line.

(3) Use Certified Reference Materials (CRM's) (See Citation 1) audit gases that have been certified by comparison to National Institute of Standards and Technology (NIST) Standard Reference Materials (SRM's) or EPA Protocol Gases following the most recent edition of the EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards (See Citation 2). Procedures for preparation of CRM's are described in Citation 1. Procedures for preparation of EPA Protocol Gases are described in Citation 2. In the case that a suitable audit gas level is not commercially available, Method 205 (See Citation 3) may be used to dilute CRM's or EPA Protocol Gases to the needed level. The difference between the actual concentration of the audit gas and the concentration indicated by the monitor is used to assess the accuracy of the CEMS.

5.1.3 Relative Accuracy Audit (RAA). The RAA may be conducted three of four calendar quarters, but in no more than three quarters in succession. To conduct a RAA, follow the procedure described in the applicable PS in appendix B for the relative accuracy test, except that only three sets of measurement data are required. Analyses of EPA performance audit samples are also required.

The relative difference between the mean of the RM values and the mean of the CEMS responses will be used to assess the accuracy of the CEMS.

5.1.4 Other Alternative Audits. Other alternative audit procedures may be used as approved by the Administrator for three of four calendar quarters. One RATA is required at least every four calendar quarters, except in the case where the affected facility is off-line (does not operate) in the fourth calendar quarter since the quarter of the previous RATA. In that case, the RATA shall be performed in the quarter in which the unit recommences operation. Also, cylinder gas audits are not be required for calendar quarters in which the affected facility does not operate.

5.2 Excessive Audit Inaccuracy. If the RA, using the RATA, CGA, or RAA exceeds the criteria in section 5.2.3, the CEMS is out-of-control. If the CEMS is out-of-control, take necessary corrective action to eliminate the problem. Following corrective action, the source owner or operator must audit the CEMS with a RATA, CGA, or RAA to determine if the CEMS is operating within the specifications. A RATA must always be used following an out-of-control period resulting from a RATA. The audit following corrective action does not require analysis of EPA performance audit samples. If audit results show the CEMS to be out-of-control, the CEMS operator shall report both the audit showing the CEMS to be out-of-control and the results of the audit following corrective action showing the CEMS to be operating within specifications.

5.2.1 Out-Of-Control Period Definition. The beginning of the out-of-control period is the time corresponding to the completion of the sampling for the RATA, RAA, or CGA. The end of the out-of-control period is the time corresponding to the completion of the sampling of the subsequent successful audit.

5.2.2 CEMS Data Status During Out-Of-Control Period. During the period the monitor is out-of-control, the CEMS data may not be used in calculating emission compliance nor be counted towards meeting minimum data availabilty as required and described in the applicable subpart [e.g., §60.47a(f)].

5.2.3 Criteria for Excessive Audit Inaccuracy. Unless specified otherwise in the applicable subpart, the criteria for excessive inaccuracy are:

(1) For the RATA, the allowable RA in the applicable PS in appendix B.

(2) For the CGA, ±15 percent of the average audit value or ±5 ppm, whichever is greater.

(3) For the RAA, ±15 percent of the three run average or ±7.5 percent of the applicable standard, whichever is greater.

5.3 Criteria for Acceptable QC Procedure. Repeated excessive inaccuracies (i.e., out-of-control conditions resulting from the quarterly audits) indicates the QC procedures are inadequate or that the CEMS is incapable of providing quality data. Therefore, whenever excessive inaccuracies occur for two consective quarters, the source owner or operator must revise the QC procedures (see section 3) or modify or replace the CEMS.

6. Calculations for CEMS Data Accuracy

6.1 RATA RA Calculation. Follow the equations described in section 8 of appendix B, PS 2 to calculate the RA for the RATA. The RATA must be calculated in units of the applicable emission standard (e.g., ng/J).

6.2 RAA Accuracy Calculation. Use the calculation procedure in the relevant performance specification to calculate the accuracy for the RAA. The RAA must be calculated in the units of the applicable emission standard.

6.3 CGA Accuracy Calculation. Use Equation 1-1 to calculate the accuracy for the CGA, which is calculated in units of the appropriate concentration (e.g., ppm SO_2 or percent O_2). Each component of the CEMS must meet the acceptable accuracy requirement.

$$A = \frac{C_m - C_a}{C_a} \times 100 \qquad Eq.\ 1\text{-}1$$

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where:

A = Accuracy of the CEMS, percent.

C_m = Average CEMS response during audit in units of applicable standard or appropriate concentration.

C_a = Average audit value (CGA certified value or three-run average for RAA) in units of applicable standard or appropriate concentration.

6.4 Example Accuracy Calculations. Example calculations for the RATA, RAA, and CGA are available in Citation 3.

7. Reporting Requirements

At the reporting interval specified in the applicable regulation, report for each CEMS the accuracy results from section 6 and the CD assessment results from section 4. Report the drift and accuracy information as a Data Assessment Report (DAR), and include one copy of this DAR for each quarterly audit with the report of emissions required under the applicable subparts of this part.

As a minimum, the DAR must contain the following information:

1. Source owner or operator name and address.

2. Identification and location of monitors in the CEMS.

3. Manufacturer and model number of each monitor in the CEMS.

4. Assessment of CEMS data accuracy and date of assessment as determined by a RATA, RAA, or CGA described in section 5 including the RA for the RATA, the A for the RAA or CGA, the RM results, the cylinder gases certified values, the CEMS responses, and the calculations results as defined in section 6. If the accuracy audit results show the CEMS to be out-of-control, the CEMS operator shall report both the audit results showing the CEMS to be out-of-control and the results of the audit following corrective action showing the CEMS to be operating within specifications.

5. Results from EPA performance audit samples described in section 5 and the applicable RM's.

6. Summary of all corrective actions taken when CEMS was determined out-of-control, as described in sections 4 and 5.

An example of a DAR format is shown in Figure 1.

8. Bibliography

1. “A Procedure for Establishing Traceability of Gas Mixtures to Certain National Bureau of Standards Standard Reference Materials.” Joint publication by NBS and EPA-600/7-81-010, Revised 1989. Available from the U.S. Environmental Protection Agency. Quality Assurance Division (MD-77). Research Triangle Park, NC 27711.

2. “EPA Traceability Protocol For Assay And Certification Of Gaseous Calibration Standards.” EPA-600/R-97/121, September 1997. Available from EPA's Emission Measurement Center at *http://www.epa.gov/ttn/emc.*

3. Method 205, “Verification of Gas Dilution Systems for Field Instrument Calibrations,” 40 CFR 51, appendix M.

FIGURE 1—EXAMPLE FORMAT FOR DATA ASSESSMENT REPORT

Period ending date__________

Year__________

Company name__________

Plant name__________

Source unit no.__________

CEMS manufacturer__________

Model no.__________

CEMS serial no.__________

CEMS type (e.g., in situ)__________

CEMS sampling location (e.g., control device outlet)__________

CEMS span values as per the applicable regulation: ______ (e.g., SO_2 ____ ppm, NO_X ____ ppm). _________

I. Accuracy assessment results (Complete A, B, or C below for each CEMS or for each pollutant and diluent analyzer, as applicable.) If the quarterly audit results show the CEMS to be out-of-control, report the results of both the quarterly audit and the audit following corrective action showing the CEMS to be operating properly.

A. Relative accuracy test audit (RATA) for ____ (e.g., SO_2 in ng/J).

1. Date of audit ____.

2. Reference methods (RM's) used ____ (e.g., Methods 3 and 6).

3. Average RM value ____ (e.g., ng/J, mg/dsm^3, or percent volume).

4. Average CEMS value ____.

5. Absolute value of mean difference [d] ____.

6. Confidence coefficient [CC] ____.

7. Percent relative accuracy (RA) ____ percent.

8. EPA performance audit results:

a. Audit lot number (1) ____ (2) ____

b. Audit sample number (1) ____ (2) ____

c. Results (mg/dsm^3) (1) ____ (2) ____

d. Actual value (mg/dsm^3)* (1) ____ (2) ____

e. Relative error* (1) ____ (2) ____

B. Cylinder gas audit (CGA) for ____ (e.g., SO_2 in ppm).

	Audit point 1	**Audit point 2**	
1. Date of audit			
2. Cylinder ID number			

3. Date of certification			
4. Type of certification			(e.g., EPA Protocol 1 or CRM).
5. Certified audit value			(e.g., ppm).
6. CEMS response value			(e.g., ppm).
7. Accuracy			percent.

C. Relative accuracy audit (RAA) for ____ (e.g., SO_2 in ng/J).

1. Date of audit ____.

2. Reference methods (RM's) used ____ (e.g., Methods 3 and 6).

3. Average RM value ____ (e.g., ng/J).

4. Average CEMS value ____.

5. Accuracy ____ percent.

6. EPA performance audit results:

a. Audit lot number (1) ____ (2) ____

b. Audit sample number (1) ____ (2) ____

c. Results (mg/dsm^3) (1) ____ (2) ____

d. Actual value (mg/dsm^3) *(1) ____ (2)

e. Relative error* (1) ____ (2) ____

*To be completed by the Agency.

D. Corrective action for excessive inaccuracy.

1. Out-of-control periods.

a. Date(s) ____.

b. Number of days ____.

2. Corrective action taken____________________

3. Results of audit following corrective action. (Use format of A, B, or C above, as applicable.)

II. Calibration drift assessment.

A. Out-of-control periods.

1. Date(s) ____.

2. Number of days ____.

B. Corrective action taken____________________

Procedure 2—Quality Assurance Requirements for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources

1.0 What Are the Purpose and Applicability of Procedure 2?

The purpose of Procedure 2 is to establish the minimum requirements for evaluating the effectiveness of quality control (QC) and quality assurance (QA) procedures and the quality of data produced by your particulate matter (PM) continuous emission monitoring system (CEMS). Procedure 2 applies to PM CEMS used for continuously determining compliance with emission standards or operating permit limits as specified in an applicable regulation or permit. Other QC procedures may apply to diluent (*e.g.,* O_2) monitors and other auxiliary monitoring equipment included with your CEMS to facilitate PM measurement or determination of PM concentration in units specified in an applicable regulation.

1.1 What measurement parameter does Procedure 2 address? Procedure 2 covers the instrumental measurement of PM as defined by your source's applicable reference method (no Chemical Abstract Service number assigned).

1.2 For what types of devices must I comply with Procedure 2? You must comply with Procedure 2 for the total equipment that:

(1) We require you to install and operate on a continuous basis under the applicable regulation, and

(2) You use to monitor the PM mass concentration associated with the operation of a process or emission control device.

1.3 What are the data quality objectives (DQOs) of Procedure 2? The overall DQO of Procedure 2 is the generation of valid, representative data that can be transferred into useful information for determining PM CEMS concentrations averaged over a prescribed interval. Procedure 2 is also closely associated with Performance Specification 11 (PS-11).

(1) Procedure 2 specifies the minimum requirements for controlling and assessing the quality of PM CEMS data submitted to us or the delegated permitting authority.

(2) You must meet these minimum requirements if you are responsible for one or more PM CEMS used for compliance monitoring. We encourage you to develop and implement a more extensive QA program or to continue such programs where they already exist.

1.4 What is the intent of the QA/QC procedures specified in Procedure 2? Procedure 2 is intended to establish the minimum QA/QC requirements for PM CEMS and is presented in general terms to allow you to develop a program that is most effective for your circumstances. You may adopt QA/QC procedures that go beyond these minimum requirements to ensure compliance with applicable regulations.

1.5 When must I comply with Procedure 2? You must comply with the basic requirements of Procedure 2 immediately following successful completion of the initial correlation test of PS-11.

2.0 What Are the Basic Requirements of Procedure 2?

Procedure 2 requires you to perform periodic evaluations of PM CEMS performance and to develop and implement QA/QC programs to ensure that PM CEMS data quality is maintained.

2.1 What are the basic functions of Procedure 2?

(1) Assessment of the quality of your PM CEMS data by estimating measurement accuracy;

(2) Control and improvement of the quality of your PM CEMS data by implementing QC requirements and corrective actions until the data quality is acceptable; and

(3) Specification of requirements for daily instrument zero and upscale drift checks and daily sample volume checks, as well as routine response correlation audits, absolute correlation audits, sample volume audits, and relative response audits.

3.0 What Special Definitions Apply to Procedure 2?

The definitions in Procedure 2 include those provided in PS-11 of Appendix B, with the following additions:

3.1 “Absolute Correlation Audit (ACA)” means an evaluation of your PM CEMS response to a series of reference standards covering the full measurement range of the instrument (*e.g.,* 4 mA to 20 mA).

3.2 “Correlation Range” means the range of PM CEMS responses used in the complete set of correlation test data.

3.3 “PM CEMS Correlation” means the site-specific relationship (*i.e.,* a regression equation) between the output from your PM CEMS (*e.g.,* mA) and the particulate concentration, as determined by the reference method. The PM CEMS correlation is expressed in the same units as the PM concentration measured by your PM CEMS (*e.g.,* mg/acm). You must derive this relation from PM CEMS response data and manual reference method data that were gathered simultaneously. These data must be representative of the full range of source and control device operating conditions that you expect to occur. You must develop the correlation by performing the steps presented in sections 12.2 and 12.3 of PS-11.

3.4 “Reference Method Sampling Location” means the location in your source's exhaust duct from which you collect manual reference method data for developing your PM CEMS correlation and for performing relative response audits (RRAs) and response correlation audits (RCAs).

3.5 “Response Correlation Audit (RCA)” means the series of tests specified in section 10.3(8) of this procedure that you conduct to ensure the continued validity of your PM CEMS correlation.

3.6 “Relative Response Audit (RRA)” means the brief series of tests specified in section 10.3(6) of this procedure that you conduct between consecutive RCAs to ensure the continued validity of your PM CEMS correlation.

3.7 “Sample Volume Audit (SVA)” means an evaluation of your PM CEMS measurement of sample volume if your PM CEMS determines PM concentration based on a measure of PM mass in an extracted sample volume and an independent determination of sample volume.

4.0 Interferences [Reserved]

5.0 What Do I Need To Know To Ensure the Safety of Persons Using Procedure 2?

People using Procedure 2 may be exposed to hazardous materials, operations, and equipment. Procedure 2 does not purport to address all of the safety issues associated with its use. It is your responsibility to establish appropriate safety and health practices and determine the applicable regulatory limitations before performing this procedure. You must consult your CEMS user's manual for specific precautions to be taken with regard to your PM CEMS procedures.

6.0 What Equipment and Supplies Do I Need? [Reserved]

7.0 What Reagents and Standards Do I Need?

You will need reference standards or procedures to perform the zero drift check, the upscale drift check, and the sample volume check.

7.1 What is the reference standard value for the zero drift check? You must use a zero check value that is no greater than 20 percent of the PM CEMS's response range. You must obtain documentation on the zero check value from your PM CEMS manufacturer.

7.2 What is the reference standard value for the upscale drift check? You must use an upscale check value that produces a response between 50 and 100 percent of the PM CEMS's response range. For a PM CEMS that produces output over a range of 4 mA to 20 mA, the upscale check value must produce a response in the range of 12 mA to 20 mA. You must obtain documentation on the upscale check value from your PM CEMS manufacturer.

7.3 What is the reference standard value for the sample volume check? You must use a reference standard value or procedure that produces a sample volume value equivalent to the normal sampling rate. You must obtain documentation on the sample volume value from your PM CEMS manufacturer.

8.0 What Sample Collection, Preservation, Storage, and Transport Are Relevant to This Procedure? [Reserved]

9.0 What Quality Control Measures Are Required by This Procedure for My PM CEMS?

You must develop and implement a QC program for your PM CEMS. Your QC program must, at a minimum, include written procedures that describe, in detail, complete step-by-step procedures and operations for the activities in paragraphs (1) through (8) of this section.

(1) Procedures for performing drift checks, including both zero drift and upscale drift and the sample volume check (see sections 10.2(1), (2), and (5)).

(2) Methods for adjustment of PM CEMS based on the results of drift checks, sample volume checks (if applicable), and the periodic audits specified in this procedure.

(3) Preventative maintenance of PM CEMS (including spare parts inventory and sampling probe integrity).

(4) Data recording, calculations, and reporting.

(5) RCA and RRA procedures, including sampling and analysis methods, sampling strategy, and structuring test conditions over the prescribed range of PM concentrations.

(6) Procedures for performing ACAs and SVAs and methods for adjusting your PM CEMS response based on ACA and SVA results.

(7) Program of corrective action for malfunctioning PM CEMS, including flagged data periods.

(8) For extractive PM CEMS, procedures for checking extractive system ducts for material accumulation.

9.1 What QA/QC documentation must I have? You are required to keep the written QA/QC procedures on record and available for inspection by us, the State, and/or local enforcement agency for the life of your CEMS or until you are no longer subject to the requirements of this procedure.

9.2 How do I know if I have acceptable QC procedures for my PM CEMS? Your QC procedures are inadequate or your PM CEMS is incapable of providing quality data if you fail two consecutive QC audits (*i.e.,* out-of-control conditions resulting from the annual audits, quarterly audits, or daily checks). Therefore, if you fail the same two consecutive audits, you must revise your QC procedures or modify or replace your PM CEMS to correct the deficiencies causing the excessive inaccuracies (see section 10.4 for limits for excessive audit inaccuracy).

10.0 What Calibration/Correlation and Standardization Procedures Must I Perform for My PM CEMS?

You must generate a site-specific correlation for each of your PM CEMS installation(s) relating response from your PM CEMS to results from simultaneous PM reference method testing. The PS-11 defines procedures for developing the correlation and defines a series of statistical parameters for assessing acceptability of the correlation. However, a critical component of your PM CEMS correlation process is ensuring the accuracy and precision of reference method data. The activities listed in sections 10.1 through 10.10 assure the quality of the correlation.

10.1 When should I use paired trains for reference method testing? Although not required, we recommend that you should use paired-train reference method testing to generate data used to develop your PM CEMS correlation and for RCA testing. Guidance on the use of paired sampling trains can be found in the PM CEMS Knowledge Document (see section 16.5 of PS-11).

10.2 What routine system checks must I perform on my PM CEMS? You must perform routine checks to ensure proper operation of system electronics and optics, light and radiation sources and detectors, and electric or electro-mechanical systems. Necessary components of the routine system checks will depend on design details of your PM CEMS. As a minimum, you must verify the system operating parameters listed in paragraphs (1) through (5) of this section on a daily basis. Some PM CEMS may perform one or more of these functions automatically or as an integral portion of unit operations; for other PM CEMS, you must initiate or perform one or more of these functions manually.

(1) You must check the zero drift to ensure stability of your PM CEMS response to the zero check value. You must determine system output on the most sensitive measurement range when the PM CEMS is challenged with a zero reference standard or procedure. You must, at a minimum, adjust your PM CEMS whenever the daily zero drift exceeds 4 percent.

(2) You must check the upscale drift to ensure stability of your PM CEMS response to the upscale check value. You must determine system output when the PM CEMS is challenged with a reference standard or procedure corresponding to the upscale check value. You must, at a minimum, adjust your PM CEMS whenever the daily upscale drift check exceeds 4 percent.

(3) For light-scattering and extinction-type PM CEMS, you must check the system optics to ensure that system response has not been altered by the condition of optical components, such as fogging of lens and performance of light monitoring devices.

(4) You must record data from your automatic drift-adjusting PM CEMS before any adjustment is made. If your PM CEMS automatically adjusts its response to the corrected calibration values (*e.g.,* microprocessor control), you must program your PM CEMS to record the unadjusted concentration measured in the drift check before resetting the calibration. Alternately, you may program your PM CEMS to record the amount of adjustment.

(5) For extractive PM CEMS that measure the sample volume and use the measured sample volume as part of calculating the output value, you must check the sample volume on a daily basis to verify the accuracy of the sample volume measuring equipment. This sample volume check must be done at the normal sampling rate of your PM CEMS. You must adjust your PM CEMS sample volume measurement whenever the daily sample volume check error exceeds 10 percent.

10.3 What are the auditing requirements for my PM CEMS? You must subject your PM CEMS to an ACA and an SVA, as applicable, at least once each calendar quarter. Successive quarterly audits must occur no closer than 2 months apart. You must conduct an RCA and an RRA at the frequencies specified in the applicable regulation or facility operating permit. An RRA or RCA conducted during any calendar quarter can take the place of the ACA required for that calendar quarter. An RCA conducted during the period in which an RRA is required can take the place of the RRA for that period.

(1) When must I perform an ACA? You must perform an ACA each quarter unless you conduct an RRA or RCA during that same quarter.

(2) How do I perform an ACA? You perform an ACA according to the procedure specified in paragraphs (2)(i) through (v) of this section.

(i) You must challenge your PM CEMS with an audit standard or an equivalent audit reference to reproduce the PM CEMS's measurement at three points within the following ranges:

Audit point	Audit range
1	0 to 20 percent of measurement range
2	40 to 60 percent of measurement range
3	70 to 100 percent of measurement range

(ii) You must then challenge your PM CEMS three times at each audit point and use the average of the three responses in determining accuracy at each audit point. Use a separate audit standard for audit points 1, 2, and 3. Challenge the PM CEMS at each audit point for a sufficient period of time to ensure that your PM CEMS response has stabilized.

(iii) Operate your PM CEMS in the mode, manner, and range specified by the manufacturer.

(iv) Store, maintain, and use audit standards as recommended by the manufacturer.

(v) Use the difference between the actual known value of the audit standard and the response of your PM CEMS to assess the accuracy of your PM CEMS.

(3) When must I perform an SVA? You must perform an audit of the measured sample volume (*e.g.,* the sampling flow rate for a known time) once per quarter for applicable PM CEMS with an extractive sampling system. Also, you must perform and pass an SVA prior to initiation of any of the reference method data collection runs for an RCA or RRA.

(4) How do I perform an SVA? You perform an SVA according to the procedure specified in paragraphs (4)(i) through (iii) of this section.

(i) You perform an SVA by independently measuring the volume of sample gas extracted from the stack or duct over each batch cycle or time period with a calibrated device. You may make this measurement either at the inlet or outlet of your PM CEMS, so long as it measures the sample gas volume without including any dilution or recycle air. Compare the measured volume with the volume reported by your PM CEMS for the same cycle or time period to calculate sample volume accuracy.

(ii) You must make measurements during three sampling cycles for batch extractive monitors (*e.g.,* Beta-gauge) or during three periods of at least 20 minutes for continuous extractive PM CEMS.

(iii) You may need to condense, collect, and measure moisture from the sample gas prior to the calibrated measurement device (*e.g.,* dry gas meter) and correct the results for moisture content. In any case, the volumes measured by the calibrated device and your PM CEMS must be on a consistent temperature, pressure, and moisture basis.

(5) How often must I perform an RRA? You must perform an RRA at the frequency specified in the applicable regulation or facility operating permit. You may conduct an RCA instead of an RRA during the period when the RRA is required.

(6) How do I perform an RRA? You must perform the RRA according to the procedure specified in paragraphs (6)(i) and (ii) of this section.

(i) You perform an RRA by collecting three simultaneous reference method PM concentration measurements and PM CEMS measurements at the as-found source operating conditions and PM concentration.

(ii) We recommend that you use paired trains for reference method sampling. Guidance on the use of paired sampling trains can be found in the PM CEMS Knowledge Document (see section 16.5 of PS-11).

(7) How often must I perform an RCA? You must perform an RCA at the frequency specified in the applicable regulation or facility operating permit.

(8) How do I perform an RCA? You must perform the RCA according to the procedures for the PM CEMS correlation test described in PS-11, section 8.6, except that the minimum number of runs required is 12 in the RCA instead of 15 as specified in PS-11.

(9) What other alternative audits can I use? You can use other alternative audit procedures as approved by us, the State, or local agency for the quarters when you would conduct ACAs.

10.4 What are my limits for excessive audit inaccuracy? Unless specified otherwise in the applicable subpart, the criteria for excessive audit inaccuracy are listed in paragraphs (1) through (6) of this section.

(1) What are the criteria for excessive zero or upscale drift? Your PM CEMS is out of control if the zero drift check or upscale drift check either exceeds 4 percent for five consecutive daily periods or exceeds 8 percent for any one day.

(2) What are the criteria for excessive sample volume measurement error? Your PM CEMS is out of control if sample volume check error exceeds 10 percent for five consecutive daily periods or exceeds 20 percent for any one day.

(3) What are the criteria for excessive ACA error? Your PM CEMS is out of control if the results of any ACA exceed ±10 percent of the average audit value, as calculated using Equation 2-1a, or 7.5 percent of the applicable standard, as calculated using Equation 2-1b, whichever is greater.

(4) What is the criterion for excessive SVA error? Your PM CEMS is out of control if results exceed ±5 percent of the average sample volume audit value.

(5) What are the criteria for passing a RCA? To pass a RCA, you must meet the criteria specified in paragraphs (5)(i) and (ii) of this section. If your PM CEMS fails to meet these RCA criteria, it is out of control.

(i) For all 12 data points, the PM CEMS response value can be no greater than the greatest PM CEMS response value used to develop your correlation curve.

(ii) At least 75 percent of a minimum number of 12 sets of PM CEMS and reference method measurements must fall within a specified area on a graph of the correlation regression line. The specified area on the graph of the correlation regression line is defined by two lines parallel to the correlation regression line, offset at a distance of ±25 percent of the numerical emission limit value from the correlation regression line. If any of the PM CEMS response values resulting from your RCA are lower than the lowest PM CEMS response value of your existing correlation curve, you may extend your correlation regression line to the point corresponding to the lowest PM CEMS response value obtained during the RCA. This extended correlation regression line must then be used to determine if the RCA data meets this criterion.

(6) What are the criteria to pass a RRA? To pass a RRA, you must meet the criteria specified in paragraphs (6)(i) and (ii) of this section. If your PM CEMS fails to meet these RRA criteria, it is out of control.

(i) For all three data points, the PM CEMS response value can be no greater than the greatest PM CEMS response value used to develop your correlation curve.

(ii) At least two of the three sets of PM CEMS and reference method measurements must fall within the same specified area on a graph of the correlation regression line as required for the RCA and described in paragraph (5)(ii) of this section.

10.5 What do I do if my PM CEMS is out of control? If your PM CEMS is out of control, you must take the actions listed in paragraphs (1) and (2) of this section.

(1) You must take necessary corrective action to eliminate the problem and perform tests, as appropriate, to ensure that the corrective action was successful.

(i) Following corrective action, you must repeat the previously failed audit to confirm that your PM CEMS is operating within the specifications.

(ii) If your PM CEMS failed an RRA, you must take corrective action until your PM CEMS passes the RRA criteria. If the RRA criteria cannot be achieved, you must perform an RCA.

(iii) If your PM CEMS failed an RCA, you must follow procedures specified in section 10.6 of this procedure.

(2) You must report both the audit showing your PM CEMS to be out of control and the results of the audit following corrective action showing your PM CEMS to be operating within specifications.

10.6 What do I do if my PM CEMS fails an RCA? After an RCA failure, you must take all applicable actions listed in paragraphs (1) through (3) of this section.

(1) Combine RCA data with data from the active PM CEMS correlation and perform the mathematical evaluations defined in PS-11 for development of a PM CEMS correlation, including examination of alternate correlation models (*i.e.,* linear, polynomial, logarithmic, exponential, and power). If the expanded data base and revised correlation meet PS-11 statistical criteria, use the revised correlation.

(2) If the criteria specified in paragraph (1) of this section are not achieved, you must develop a new PM CEMS correlation based on revised data. The revised data set must consist of the test results from only the RCA. The new data must meet all requirements of PS-11 to develop a revised PM CEMS correlation, except that the minimum number of sets of PM CEMS and reference method measurements is 12 instead of the minimum of 15 sets required by PS-11. Your PM CEMS is considered to be back in controlled status when the revised correlation meets all of the performance criteria specified in section 13.2 of PS-11.

(3) If the actions in paragraphs (1) and (2) of this section do not result in an acceptable correlation, you must evaluate the cause(s) and comply with the actions listed in paragraphs (3)(i) through (iv) of this section within 90 days after the completion of the failed RCA.

(i) Completely inspect your PM CEMS for mechanical or operational problems. If you find a mechanical or operational problem, repair your PM CEMS and repeat the RCA.

(ii) You may need to relocate your PM CEMS to a more appropriate measurement location. If you relocate your PM CEMS, you must perform a new correlation test according to the procedures specified in PS-11.

(iii) The characteristics of the PM or gas in your source's flue gas stream may have changed such that your PM CEMS measurement technology is no longer appropriate. If this is the case, you must install a PM CEMS with measurement technology that is appropriate for your source's flue gas characteristics. You must perform a new correlation test according to the procedures specified in PS-11.

(iv) If the corrective actions in paragraphs (3)(i) through (iii) of this section were not successful, you must petition us, the State, or local agency for approval of alternative criteria or an alternative for continuous PM monitoring.

10.7 When does the out-of-control period begin and end? The out-of-control period begins immediately after the last test run or check of an unsuccessful RCA, RRA, ACA, SVA, drift check, or sample volume check. The out-of-control period ends immediately after the last test run or check of the subsequent successful audit or drift check.

10.8 Can I use the data recorded by my PM CEMS during out-of-control periods? During any period when your PM CEMS is out of control, you may not use your PM CEMS data to calculate emission compliance or to meet minimum data availability requirements described in the applicable regulation.

10.9 What are the QA/QC reporting requirements for my PM CEMS? You must report the accuracy results for your PM CEMS, specified in section 10.4 of this procedure, at the interval specified in the applicable regulation. Report the drift and accuracy information as a Data Assessment Report (DAR), and include one copy of this DAR for each quarterly audit with the report of emissions required under the applicable regulation. An example DAR is provided in Procedure 1, Appendix F of this part.

10.10 What minimum information must I include in my DAR? As a minimum, you must include the information listed in paragraphs (1) through (5) of this section in the DAR:

(1) Your name and address.

(2) Identification and location of monitors in your CEMS.

(3) Manufacturer and model number of each monitor in your CEMS.

(4) Assessment of PM CEMS data accuracy/acceptability, and date of assessment, as determined by an RCA, RRA, ACA, or SVA described in section 10, including the acceptability determination for the RCA or RRA, the accuracy for the ACA or SVA, the reference method results, the audit standards, your PM CEMS responses, and the calculation results as defined in section 12. If the accuracy audit results show your PM CEMS to be out of control, you must report both the audit results showing your PM CEMS to be out of control and the results of the audit following corrective action showing your PM CEMS to be operating within specifications.

(5) Summary of all corrective actions you took when you determined your PM CEMS to be out of control, as described in section 10.5, or after failing on RCA, as described in section 10.6.

10.7 Where and how long must I retain the QA data that this procedure requires me to record for my PM CEMS? You must keep the records required by this procedure for your PM CEMS onsite and available for inspection by us, the State, and/or local enforcement agency for a period of 5 years.

11.0 What Analytical Procedures Apply to This Procedure?

Sample collection and analysis are concurrent for this procedure. You must refer to the appropriate reference method for the specific analytical procedures.

12.0 What Calculations and Data Analysis Must I Perform for my PM CEMS?

(1) How do I determine RCA and RRA acceptability? You must plot each of your PM CEMS and reference method data sets from an RCA or RRA on a graph based on your PM CEMS correlation line to determine if the criteria in paragraphs 10.4(5) or (6), respectively, are met.

(2) How do I calculate ACA accuracy? You must use either Equation 2-1a or 2-1b to calculate ACA accuracy for each of the three audit points. However, when calculating ACA accuracy for the first audit point (0 to 20 percent of measurement range), you must use Equation 2-1b to calculate ACA accuracy if the reference standard value (R_v) equals zero.

$$\text{ACA Accuracy} = \frac{|R_{CEM} - R_V|}{R_V} \times 100\% \qquad \text{Eq. 2-1a}$$

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Where:

ACA Accuracy = The ACA accuracy at each audit point, in percent,

R_{CEM} = Your PM CEMS response to the reference standard, and

R_V = The reference standard value.

$$\text{ACA Accuracy} = \frac{|C_{CEM} - C_{RV}|}{C_s} \times 100\% \qquad \text{Eq. 2-1b}$$

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Where:

ACA Accuracy = The ACA accuracy at each audit point, in percent,

C_{CEM} = The PM concentration that corresponds to your PM CEMS response to the reference standard, as calculated using the correlation equation for your PM CEMS,

C_{RV} = The PM concentration that corresponds to the reference standard value in units consistent with C_{CEM}, and

C_s = The PM concentration that corresponds to the applicable emission limit in units consistent with C_{CEM}.

(3) How do I calculate daily upscale and zero drift? You must calculate the upscale drift using Equation 2-2 and the zero drift using Equation 2-3:

$$UD = \frac{|R_{CEM} - R_U|}{R_r} \times 100 \qquad \text{Eq. 2-2}$$

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Where:

UD = The upscale drift of your PM CEMS, in percent,

R_{CEM} = Your PM CEMS response to the upscale check value,

R_U = The upscale check value, and

R_r = The response range of the analyzer.

$$ZD = \frac{|R_{CEM} - R_L|}{R_r} \times 100 \qquad \text{Eq. 2-3}$$

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Where:

ZD = The zero (low-level) drift of your PM CEMS, in percent,

R_{CEM} = Your PM CEMS response of the zero check value,

R_L = The zero check value, and

R_r = The response range of the analyzer.

(4) How do I calculate SVA accuracy? You must use Equation 2-4 to calculate the accuracy, in percent, for each of the three SVA tests or the daily sample volume check:

$$\text{SVA Accuracy} = \frac{|V_M - V_R|}{V_R} \times 100 \qquad \text{Eq. 2-4}$$

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Where:

SVA Accuracy = The SVA accuracy at each audit point, in percent,

V_M = Sample gas volume determined/reported by your PM CEMS (*e.g.,* dscm), and

V_R = Sample gas volume measured by the independent calibrated reference device (*e.g.,* dscm) for the SVA or the reference value for the daily sample volume check.

Note: Before calculating SVA accuracy, you must correct the sample gas volumes measured by your PM CEMS and the independent calibrated reference device to the same basis of temperature, pressure, and moisture content. You must document all data and calculations.

13.0 Method Performance [Reserved]

14.0 Pollution Prevention [Reserved]

15.0 Waste Management [Reserved]

16.0 Which References are Relevant to This Method? [Reserved]

17.0 What Tables, Diagrams, Flowcharts, and Validation Data Are Relevant to This Method? [Reserved]

Procedure 3—Quality Assurance Requirements for Continuous Opacity Monitoring Systems at Stationary Sources

1.0 What are the purpose and applicability of Procedure 3?

The purpose of Procedure 3 is to establish quality assurance and quality control (QA/QC) procedures for continuous opacity monitoring systems (COMS). Procedure 3 applies to COMS used to demonstrate continuous compliance with opacity standards specified in new source performance standards (NSPS) promulgated by EPA pursuant to section 111(b) of the Clean Air Act, 42 U.S.C. 7411(b)—Standards of Performance for New Stationary Sources.

1.1 *What are the data quality objectives of Procedure 3?* The overall data quality objective (DQO) of Procedure 3 is the generation of valid and representative opacity data. Procedure 3 specifies the minimum requirements for controlling and assessing the quality of COMS data submitted to us or the delegated regulatory agency. Procedure 3 requires you to perform periodic evaluations of a COMS performance and to develop and implement QA/QC programs to ensure that COMS data quality is maintained.

1.2 *What is the intent of the QA/QC procedures specified in Procedure 3?* Procedure 3 is intended to establish the minimum QA/QC requirements to verify and maintain an acceptable level of quality of the data produced by COMS. It is presented in general terms to allow you to develop a program that is most effective for your circumstances.

1.3 *When must I comply with Procedure 3?* You must comply with Procedure 3 no later than November 12, 2014.

2.0 What are the basic functions of Procedure 3?

The basic functions of Procedure 3 are assessment of the quality of your COMS data and control and improvement of the quality of the data by implementing QC requirements and corrective actions. Procedure 3 provides requirements for:

(1) Daily instrument zero and upscale drift checks and status indicators checks;

(2) Quarterly performance audits which include the following assessments:

(i) Optical alignment,

(ii) Calibration error, and

(iii) Zero compensation.

Sources that achieve quality assured data for four consecutive quarters may reduce their auditing frequency to semi-annual. If a performance audit is failed, the source must resume quarterly testing for that audit requirement until it again demonstrates successful performance over four consecutive quarters.

(3) Annual zero alignment.

3.0 What special definitions apply to Procedure 3?

The definitions in Procedure 3 include those provided in Performance Specification 1 (PS-1) of Appendix B of this part and ASTM D6216-12 and the following additional definitions.

3.1 Out-of-control periods. Out-of-control periods mean that one or more COMS parameters falls outside of the acceptable limits established by this rule.

(1) *Daily Assessments.* Whenever the calibration drift (CD) exceeds twice the specification of PS-1, the COMS is out-of-control. The beginning of the out-of-control period is the time corresponding to the completion of the daily calibration drift check. The end of the out-of-control period is the time corresponding to the completion of appropriate adjustment and subsequent successful CD assessment.

(2) *Quarterly and Annual Assessments.* Whenever an annual zero alignment or quarterly performance audit fails to meet the criteria established in paragraphs (2) and (3) of section 10.4, the COMS is out-of-control. The beginning of the out-of-control period is the time corresponding to the completion of the performance audit indicating the failure to meet these established criteria. The end of the out-of-control period is the time corresponding to the completion of appropriate corrective actions and the subsequent successful audit (or, if applicable, partial audit).

4.0 What interferences must I avoid?

Opacity cannot be measured accurately in the presence of condensed water vapor. Thus, COMS opacity compliance determinations cannot be made when condensed water vapor is present, such as downstream of a wet scrubber without a reheater or at other saturated flue gas locations. Therefore, COMS must be located where condensed water vapor is not present.

5.0 What do I need to know to ensure the safety of persons using Procedure 3?

Those implementing Procedure 3 may be exposed to hazardous materials, operations and equipment. Procedure 3 does not purport to address all of the safety issues associated with its use. It is your responsibility to establish appropriate health and safety practices and determine the applicable regulatory limitations before performing this procedure. You should consult the COMS user's manual for specific precautions to take.

6.0 What equipment and supplies do I need?

The equipment and supplies that you need are specified in PS-1. You are not required to purchase a new COMS if your existing COMS meets the requirements specified in Procedure 3.

7.0 What reagents and standards do I need?

The reagents and standards that you need are specified in PS-1. You are not required to purchase a new COMS if your existing COMS meets the requirements specified in Procedure 3.

8.0 What sample collection, preservation, storage, and transport are relevant to this procedure? [Reserved]

9.0 What quality control measures are required by this procedure for my COMS?

You must develop and implement a QC program for your COMS. Your QC program must, at a minimum, include written procedures which describe in detail complete step-by-step procedures and operations for the activities in paragraphs (1) through (4):

(1) Procedures for performing drift checks, including both zero and upscale drift and the status indicators check,

(2) Procedures for performing quarterly performance audits,

(3) A means of checking the zero alignment of the COMS, and

(4) A program of corrective action for a malfunctioning COMS. The corrective action must include, at a minimum, the requirements specified in section 10.5.

9.1 *What QA/QC documentation must I have?* You are required to keep the QA/QC written procedures required in section 9.0 on site and available for inspection by us, the state, and/or local enforcement agencies.

9.2 *What actions must I take if I fail QC audits?* If you fail two consecutive annual audits, two consecutive quarterly audits, or five consecutive daily checks, you must either revise your QC procedures or determine if your COMS is malfunctioning. If you determine that your COMS is malfunctioning, you must take the necessary corrective action as specified in section 10.5. If you determine that your COMS requires extensive repairs, you may use a substitute COMS provided the substitute meets the requirements in section 10.6.

10.0 What calibration and standardization procedures must I perform for my COMS?

(1) You must perform daily system checks to ensure proper operation of system electronics and optics, light and radiation sources and detectors, electric or electro-mechanical systems, and general stability of the system calibration. Daily is defined as any portion of a calendar day in which a unit operates.

(2) You must subject your COMS to a performance audit to include checks of the individual COMS components and factors affecting the accuracy of the monitoring data at least once per QA operating quarter. A QA operating quarter is a calendar quarter in which a unit operates at least 168 hours.

(3) At least annually, you must perform a zero alignment by comparing the COMS simulated zero to the actual clear path zero. Annually is defined as a period wherein the unit is operating at least 28 days in a calendar year. The simulated zero device produces a simulated clear path condition or low-level opacity condition, where the energy reaching the detector is between 90 and 110 percent of the energy reaching the detector under actual clear path conditions.

10.1 *What daily system checks must I perform on my COMS?* The specific components required to undergo daily system checks will depend on the design details of your COMS. At a minimum, you must verify the system operating parameters listed in paragraphs (1) through (3) of this section. Some COMS may perform one or more of these functions automatically or as an integral portion of unit operations; other COMS may perform one or more of these functions manually.

(1) You must check the zero drift to ensure stability of your COMS response to the simulated zero device. The simulated zero device, an automated mechanism within the transmissometer that produces a simulated clear path condition or low-level opacity condition, is used to check the zero drift. You must, at a minimum, take corrective action on your COMS whenever the daily zero drift exceeds twice the applicable drift specification in section 13.3(6) of PS-1.

(2) You must check the upscale drift to ensure stability of your COMS response to the upscale drift value. The upscale calibration device, an automated mechanism (employing an attenuator or reduced reflectance device) within the transmissometer that produces an upscale opacity value is used to check the upscale drift. You must, at a minimum, take corrective action on your COMS whenever the daily upscale drift check exceeds twice the applicable drift specification in section 13.3(6) of PS-1.

(3) You must, at a minimum, check the status indicators, data acquisition system error messages, and other system self-diagnostic indicators. You must take appropriate corrective action based on the manufacturer's recommendations when the COMS is operating outside preset limits.

10.2 *What are the quarterly auditing requirements for my COMS?* At a minimum, the parameters listed in paragraphs (1) through (3) of this section must be included in the performance audit conducted on a quarterly basis as defined in section 10.0(2).

(1) For units with automatic zero compensation, you must determine the zero compensation for the COMS. The value of the zero compensation applied at the time of the audit must be calculated as equivalent opacity and corrected to stack exit conditions according to the procedures specified by the manufacturer. The compensation applied to the effluent by the monitor system must be recorded.

(2) You must conduct a three-point calibration error test of the COMS. Three calibration attenuators, either primary or secondary must meet the requirements of PS-1, with one exception. Instead of recalibrating the attenuators semi-annually, they must be recalibrated annually. If two annual calibrations agree within 0.5 percent opacity, the attenuators may then be calibrated once every five years. The three attenuators must be placed in the COMS light beam path for at least three nonconsecutive readings. All monitor responses must then be independently recorded from the COMS permanent data recorder. Additional guidance for conducting this test is included in section 8.1(3)(ii) of PS-1. The low-, mid-, and high-range calibration error results must be computed as the mean difference and 95 percent confidence interval for the difference between the expected and actual responses of the monitor as corrected to stack exit conditions. The equations necessary to perform the calculations are found in section 12.0 of PS-1. For the calibration error test method, you must use the external audit device. When the external audit device is installed, with no calibration attenuator inserted, the COMS measurement reading must be less than or equal to one percent opacity. You must also document procedures for properly handling and storing the external audit device and calibration attenuators within your written QC program.

(3) You must check the optical alignment of the COMS in accordance with the instrument manufacturer's recommendations. If the optical alignment varies with stack temperature, perform the optical alignment test when the unit is operating.

10.3 *What are the annual auditing requirements for my COMS?*

(1) You must perform the primary zero alignment method under clear path conditions. The COMS must be removed from its installation and set up under clear path conditions. There must be no adjustments to the monitor other than the establishment of the proper monitor path length and correct optical alignment of the COMS components. You must record the COMS response to a clear condition and to the COMS's simulated zero condition as percent opacity corrected to stack exit conditions. For a COMS with automatic zero compensation, you must disconnect or disable the zero compensation mechanism or record the amount of correction applied to the COMS's simulated zero condition. The response difference in percent opacity to the clear path and simulated zero conditions must be recorded as the zero alignment error. You must adjust the COMS's simulated zero device to provide the same response as the clear path condition as specified in paragraph (3) of section 10.0.

(2) As an alternative, monitors capable of allowing the installation of an external zero device may use the device for the zero alignment provided that: (1) The external zero device setting has been established for the monitor path length and recorded for the specific COMS by comparison of the COMS responses to the installed external zero device and to the clear path condition, and (2) the external zero device is demonstrated to be capable of producing a consistent zero response when it is repeatedly (i.e., three consecutive installations and removals prior to conducting the final zero alignment check) installed on the COMS. This can be demonstrated by either the manufacturer's certificate of conformance (MCOC) or actual on-site performance. The external zero device setting must be permanently set at the time of initial zeroing to the clear path zero value and protected when not in use to ensure that the setting equivalent to zero opacity does not change. The external zero device response must be checked and recorded prior to initiating the zero alignment. If the external zero device setting has changed, you must remove the COMS from the stack in order to reset the external zero device. If you employ an external zero device, you must perform the zero alignment audits with the COMS off the stack at least every three years. If the external zero device is adjusted within the three-year period, you must perform the zero alignment with the COMS off the stack no later than three years from the date of adjustment.

(3) The procedure in section 6.8 of ASTM D6216-12 is allowed.

10.4 *What are my limits for excessive audit inaccuracy?* Unless specified otherwise in the applicable subpart, the criteria for excessive inaccuracy are listed in paragraphs (1) through (4).

(1) What is the criterion for excessive zero or upscale drift? Your COMS is out-of-control if either the zero drift check or upscale drift check exceeds twice the applicable drift specification in PS-1 for any one day.

(2) What is the criterion for excessive zero alignment? Your COMS is out-of-control if the zero alignment error exceeds 2 percent opacity.

(3) What is the criterion to pass the quarterly performance audit? Your COMS is out-of-control if the results of a quarterly performance audit indicate noncompliance with the following criteria:

(i) The optical alignment indicator does not show proper alignment (i.e., does not fall within a specific reference mark or condition).

(ii) The zero compensation exceeds 4 percent opacity, or

(iii) The calibration error exceeds 3 percent opacity.

(4) What is the criterion for data capture? You must adhere to the data capture criterion specified in the applicable subpart.

10.5 *What corrective action must I take if my COMS is malfunctioning?* You must have a corrective action program in place to address the repair and/or maintenance of your COMS. The corrective action program must address routine/preventative maintenance and various types of analyzer repairs. The corrective action program must establish what diagnostic testing must be performed after each type of activity to ensure that the COMS is collecting valid, quality-assured data. Recommended maintenance and repair procedures and diagnostic testing after repairs may be found in an associated guidance document.

10.6 *What requirements must I meet if I use a temporary opacity monitor?*

(1) In the event that your certified opacity monitor has to be removed for extended service, you may install a temporary replacement monitor to obtain required opacity emissions data provided that:

(i) The temporary monitor has been certified according to ASTM D6216-12 for which a MCOC has been provided;

(ii) The use of the temporary monitor does not exceed 1080 hours (45 days) of operation per year as a replacement for a fully certified opacity monitor. After that time, the analyzer must complete a full certification according to PS-1 prior to further use as a temporary replacement monitor. Once a temporary replacement monitor has been installed and required testing and adjustments have been successfully completed, it cannot be replaced by another temporary replacement monitor to avoid the full PS-1 certification testing required after 1080 hours (45 days) of use;

(iii) The temporary monitor has been installed and successfully completed an optical alignment assessment and status indicator assessment;

(iv) The temporary monitor has successfully completed an off-stack clear path zero assessment and zero calibration value adjustment procedure;

(v) The temporary monitor has successfully completed an abbreviated zero and upscale drift check consisting of seven zero and upscale calibration value drift checks which may be conducted within a 24-hour period with not more than one calibration drift check every three hours and not less than one calibration drift check every 25 hours. Calculated zero and upscale drift requirements are the same as specified for the normal PS-1 certification;

(vi) The temporary monitor has successfully completed a three-point calibration error test;

(vii) The upscale reference calibration check value of the new monitor has been updated in the associated data recording equipment;

(viii) The overall calibration of the monitor and data recording equipment has been verified; and

(ix) The user has documented all of the above in the maintenance log.

(2) Data generated by the temporary monitor is considered valid when paragraphs (i) through (ix) in this section have been met.

10.7 *When do out-of-control periods begin and end?* The out-of-control periods are as specified in section 3.1.

10.8 *What are the limitations on the use of my COMS data collected during out-of-control periods?* During the period your COMS is out-of-control, you may not use your COMS data to calculate emission compliance or to meet minimum data capture requirements in this procedure or the applicable regulation.

10.9 *What are the QA/QC reporting requirements for my COMS?* You must report in a Data Assessment Report (DAR) the information required by sections 10.0, 10.1, 10.2, and 10.3 for your COMS at the interval specified in the applicable regulation.

10.10 *What minimum information must I include in my DAR?* At a minimum, you must include the information listed in paragraphs (1) through (5) of this section in the DAR.

(1) Name of person completing the report and facility address,

(2) Identification and location of your COMS(s),

(3) Manufacturer, model, and serial number of your COMS(s),

(4) Assessment of COMS data accuracy/acceptability and date of assessment as determined by a performance audit described in section 10.0. If the accuracy audit results show your COMS to be out-of-control, you must report both the audit results showing your COMS to be out-of-control and the results of the audit following corrective action showing your COMS to be operating within specifications, and

(5) Summary of all corrective actions you took when you determined your COMS was out-of-control.

10.11 *Where and how long must I retain the QA data that this procedure requires me to record for my COMS?* You must keep the records required by this procedure for your COMS on site and available for inspection by us, the state, and/or the local enforcement agency for the period specified in the regulations requiring the use of COMS.

11.0 What analytical procedures apply to this procedure? [Reserved]

12.0 What calculations and data analysis must I perform for my COMS?The calculations required for the quarterly performance audit are in section 12.0 of PS-1.

13.0 Method Performance [Reserved]

14.0 Pollution Prevention [Reserved]

15.0 Waste Management [Reserved]

16.0 References

16.1 Performance Specification 1-Specifications and Test Procedures for Continuous Opacity Monitoring Systems in Stationary Sources, 40 CFR part 60, Appendix B.

16.2 ASTM D6216-12-Standard Practice for Opacity Monitor Manufacturers to Certify Conformance with Design and Performance Specifications, American Society for Testing and Materials (ASTM).

17.0 What tables, diagrams, flowcharts, and validation data are relevant to this procedure? [Reserved]

Procedure 4. [Reserved]

Procedure 5. Quality Assurance Requirements for Vapor Phase Mercury Continuous Emissions Monitoring Systems and Sorbent Trap Monitoring Systems Used for Compliance Determination at Stationary Sources

1.0 Applicability and Principle

1.1 Applicability. The purpose of Procedure 5 is to establish the minimum requirements for evaluating the effectiveness of quality control (QC) and quality assurance (QA) procedures as well as the quality of data produced by vapor phase mercury (Hg) continuous emissions monitoring systems (CEMS) and sorbent trap monitoring systems. Procedure 5 applies to Hg CEMS and sorbent trap monitoring systems used for continuously determining compliance with emission standards or operating permit limits as specified in an applicable regulation or permit. Other QA/QC procedures may apply to other auxiliary monitoring equipment that may be needed to determine Hg emissions in the units of measure specified in an applicable permit or regulation.

Procedure 5 covers the measurement of Hg emissions as defined in Performance Specification 12A (PS 12A) and Performance Specification 12B (PS 12B) in appendix B to this part, *i.e.,* total vapor phase Hg representing the sum of the elemental (Hg°, CAS Number 7439-97-6) and oxidized (Hg^{+2}) forms of gaseous Hg.

Procedure 5 specifies the minimum requirements for controlling and assessing the quality of Hg CEMS and sorbent trap monitoring system data submitted to EPA or a delegated permitting authority. You must meet these minimum requirements if you are responsible for one or more Hg CEMS or sorbent trap monitoring systems used for compliance monitoring. We encourage you to develop and implement a more extensive QA program or to continue such programs where they already exist.

You must comply with the basic requirements of Procedure 5 immediately following successful completion of the initial performance test described in PS 12A or PS 12B in appendix B to this part (as applicable).

1.2 Principle. The QA procedures consist of two distinct and equally important functions. One function is the assessment of the quality of the Hg CEMS or sorbent trap monitoring system data by estimating accuracy. The other function is the control and improvement of the quality of the CEMS or sorbent trap monitoring system data by implementing QC policies and corrective actions. These two functions form a control loop: When the assessment function indicates that the data quality is inadequate, the quality control effort must be increased until the data quality is acceptable. In order to provide uniformity in the assessment and reporting of data quality, this procedure explicitly specifies assessment methods for calibration drift, system integrity, and accuracy. Several of the procedures are based on those of PS 12A and PS 12B in appendix B to this part. Because the control and corrective action function encompasses a variety of policies, specifications, standards, and corrective measures, this procedure treats QC requirements in general terms to allow each source owner or operator to develop a QC system that is most effective and efficient for the circumstances.

2.0 Definitions

2.1 *Mercury Continuous Emission Monitoring System (Hg CEMS)* means the equipment required for the determination of the total vapor phase Hg concentration in the stack effluent. The Hg CEMS consists of the following major subsystems:

2.1.1 *Sample Interface* means that portion of the CEMS used for one or more of the following: sample acquisition, sample transport, sample conditioning, and protection of the monitor from the effects of the stack effluent.

2.1.2 *Hg Analyzer* means that portion of the Hg CEMS that measures the total vapor phase Hg concentration and generates a proportional output.

2.1.3 *Data Recorder* means that portion of the CEMS that provides a permanent electronic record of the analyzer output. The data recorder may provide automatic data reduction and CEMS control capabilities.

2.2 *Sorbent Trap Monitoring System* means the total equipment required for the collection of gaseous Hg samples using paired three-partition sorbent traps as described in PS 12B in appendix B to this part.

2.3 *Span Value* means the measurement range as specified for the affected source category in the applicable regulation and/or monitoring performance specification.

2.4 *Zero, Mid-Level, and High Level Values* means the reference gas concentrations used for calibration drift assessments and system integrity checks on a Hg CEMS, expressed as percentages of the span value (*see* section 7.1 of PS 12A in appendix B to this part).

2.5 *Calibration Drift (CD)* means the absolute value of the difference between the CEMS output response and either the upscale Hg reference gas or the zero-level Hg reference gas, expressed as a percentage of the span value, when the entire CEMS, including the sampling interface, is challenged after a stated period of operation during which no unscheduled maintenance, repair, or adjustment took place.

2.6 *System Integrity (SI) Check* means a test procedure assessing transport and measurement of oxidized Hg by a Hg CEMS. In particular, system integrity is expressed as the absolute value of the difference between the CEMS output response and the reference value of either a mid- or high-level mercuric chloride ($HgCl_2$) reference gas, as a percentage of span, when the entire CEMS, including the sampling interface, is challenged.

2.7 *Relative Accuracy (RA)* means the absolute mean difference between the pollutant concentrations determined by a continuous monitoring system (e.g., Hg CEMS or sorbent trap monitoring system) and the values determined by a reference method (RM) plus the 2.5 percent error confidence coefficient of a series of tests divided by the mean of the RM tests. Alternatively, for sources with an average RM concentration less than 5.0 micrograms per standard cubic meter (μg/scm), the RA may be expressed as the absolute value of the difference between the mean CEMS and RM values.

2.8 *Relative Accuracy Test Audit (RATA)* means an audit test procedure consisting of at least nine runs, in which the accuracy of the total vapor phase Hg concentrations measured by a CEMS or sorbent trap monitoring system is evaluated by comparison against concurrent measurements made with a reference test method.

2.9 *Quarterly Gas Audit (QGA)* means an audit procedure in which the accuracy of the total vapor phase Hg concentrations measured by a CEMS is evaluated by challenging the CEMS with a zero and two upscale reference gases.

3.0 QC Requirements

3.1 Each source owner or operator must develop and implement a QC program. At a minimum, each QC program must include written procedures which should describe in detail, complete, step-by-step procedures and operations for each of the following activities (as applicable):

(a) Calibration drift (CD) checks of Hg CEMS.

(b) CD determination and adjustment of Hg CEMS.

(c) Weekly system integrity check procedures for Hg CEMS.

(d) Routine operation, maintenance, and QA/QC procedures for sorbent trap monitoring systems.

(e) Routine and preventive maintenance procedures for Hg CEMS (including spare parts inventory).

(f) Data recording, calculations, and reporting.

(g) Accuracy audit procedures for Hg CEMS and sorbent trap monitoring systems including sampling and analysis methods.

(h) Program of corrective action for malfunctioning Hg CEMS and sorbent trap monitoring systems.

These written procedures must be kept on record and available for inspection by the responsible enforcement agency. Also, as noted in section 5.2.4, below, whenever excessive inaccuracies of a Hg CEMS occur for two consecutive quarters, the source owner or operator must revise the current written procedures or modify or replace the CEMS or sorbent trap monitoring system to correct the deficiency causing the excessive inaccuracies.

4.0 Calibration Drift (CD) Assessment

4.1 CD Requirement. As described in 40 CFR 60.13(d) and 63.8(c), source owners and operators of Hg CEMS must check, record, and quantify the CD at two concentration values at least once daily (approximately 24 hours) in accordance with the method prescribed by the manufacturer. The Hg CEMS calibration must, as minimum, be adjusted whenever the daily zero (or low-level) CD or the daily high-level CD exceeds two times the limits of the applicable PS in appendix B of this part.

4.2 Recording Requirement for Automatic CD Adjusting CEMS. CEMS that automatically adjust the data to the corrected calibration values (e.g., microprocessor control) must either be programmed to record the unadjusted concentration measured in the CD prior to resetting the calibration, if performed, or to record the amount of adjustment.

4.3 Criteria for Excessive CD. If either the zero (or low-level) or high-level CD result exceeds twice the applicable drift specification in section 13.2 of PS 12A in appendix B to this part for five, consecutive, daily periods, the CEMS is out-of-control. If either the zero (or low-level) or high-level CD result exceeds four times the applicable drift specification in PS 12A during any CD check, the CEMS is out-of-control. If the CEMS is out-of-control, take necessary corrective action. Following corrective action, repeat the CD checks.

4.3.1 Out-Of-Control Period Definition. The beginning of the out-of-control period is the time corresponding to the completion of the fifth, consecutive, daily CD check with a CD in excess of two times the allowable limit, or the time corresponding to the completion of the daily CD check preceding the daily CD check that results in a CD in excess of four times the allowable limit. The end of the out-of-control period is the time corresponding to the completion of the CD check following corrective action that results in the CD's at both the zero (or low-level) and high-level measurement points being within the corresponding allowable CD limit (*i.e.,* either two times or four times the allowable limit in the applicable PS in appendix B).

4.3.2 CEMS Data Status During Out-of-Control Period. During the period the CEMS is out-of-control, the CEMS data may not be used either to determine compliance with an emission limit or to meet a minimum data availability requirement specified in an applicable regulation or permit.

5.0 Data Accuracy Assessment

5.1 Hg CEMS Audit Requirements. For each Hg CEMS, an accuracy audit must be performed at least once each calendar quarter. Successive quarterly audits must, to the extent practicable, be performed no less than 2 months apart. The audits must be conducted as follows:

5.1.1 Relative Accuracy Test Audit (RATA). A RATA of the Hg CEMS must be conducted at least once every four calendar quarters, except as otherwise noted in section 5.1.4 of this appendix. Perform the RATA as described in section 8.5 of PS 12A in appendix B to this part. Calculate the results according to section 12.4 of PS 12A.

5.1.2 Quarterly Gas Audit. A quarterly gas audit (QGA) may be conducted in three of four calendar quarters, but in no more than three quarters in succession. To perform a QGA, challenge the CEMS with a zero-level and two upscale level audit gases of known concentrations, first of elemental Hg and then of oxidized Hg, within the following ranges:

Audit point	Audit range
1	20 to 30% of span value.
2	50 to 60% of span value.

Sequentially inject each of the three audit gases (zero and two upscale), three times each for a total of nine injections. Inject the gases in such a manner that the entire CEMS is challenged. Do not inject the same gas concentration twice in succession.

Use elemental Hg and oxidized Hg (mercuric chloride, $HgCl_2$) audit gases that are National Institute of Standards and Technology (NIST)-certified or NIST-traceable following an EPA Traceability Protocol. If audit gas cylinders are used, do not dilute gas when challenging the Hg CEMS. For each reference gas concentration, determine the average of the three CEMS responses and subtract the average response from the reference gas value. Calculate the measurement error at each gas level using Equation 12A-1 in section 8.2 of PS 12A.

5.1.3 Relative Accuracy Audit (RAA). As an alternative to the QGA, a RAA may be conducted in three of four calendar quarters, but in no more than three quarters in succession. To conduct a RAA, follow the RATA test procedures in section 8.5 of PS 12A in appendix B to this part, except that only three test runs are required.

5.1.4 Alternative Quarterly Audits. Alternative quarterly audit procedures may be used as approved by the Administrator for three of four calendar quarters. One RATA is required at least every four calendar quarters, except in the case where the affected facility is off-line (does not operate) in the fourth calendar quarter since the quarter of the previous RATA. In that case, the RATA must be performed in the quarter in which the unit recommences operation. Also, quarterly gas audits (or RAAs, if applicable) are not required for calendar quarters in which the affected facility does not operate.

5.2 Sorbent Trap Monitoring System Audit Requirements. For each sorbent trap monitoring system, a RATA must be conducted at least once every four calendar quarters, except as otherwise noted in section 5.1.4 of this appendix. Perform the RATA as described in section 8.3 of PS 12B in appendix B to this part. Calculate the results according to section 12.4 of PS 12A.

5.3 Excessive Audit Inaccuracy. If the results of a RATA, QGA, or RAA exceed the applicable criteria in section 5.3.3, the Hg CEMS or sorbent trap monitoring system is out-of-control. If the Hg CEMS or sorbent trap monitoring system is out-of-control, take necessary corrective action to eliminate the problem. Following corrective action, the source owner or operator must audit the CEMS or sorbent trap monitoring system using the same type of test that failed to meet the accuracy criterion. For instance, a RATA must always be performed following an out-of-control period resulting from a failed RATA. Whenever audit results show the Hg CEMS or sorbent trap monitoring system to be out-of-control, the owner or operator must report both the results of the failed test and the results of the retest following corrective action showing the CEMS to be operating within specifications.

5.3.1 Out-Of-Control Period Definition. The beginning of the out-of-control period is the hour immediately following the completion of a RATA, RAA, QGA or system integrity check that fails to meet the applicable performance criteria in section 5.3.3, below. The end of the out-of-control period is the time corresponding to the completion of a subsequent successful test of the same type.

5.3.2 Monitoring Data Status During Out-Of-Control Period. During the period the monitor is out-of-control, the monitoring data may not be used to determine compliance with an applicable emission limit or to meet a minimum data availability requirement in an applicable regulation or permit.

5.3.3 Criteria for Excessive Audit Inaccuracy. Unless specified otherwise in an applicable regulation or permit, the criteria for excessive inaccuracy are:

(a) For the RATA, the allowable RA in the applicable PS in appendix B (e.g., PS 12A or PS 12B).

(b) For the QGA, ±15 percent of the average audit value or ±0.5 $\mu g/m^3$, whichever is greater.

(c) For the RAA, ±20 percent of the three run average or ±10 percent of the applicable standard, whichever is greater.

5.3.4 Criteria for Acceptable QC Procedures. Repeated excessive inaccuracies (*i.e.,* out-of-control conditions resulting from the quarterly audits) indicates the QC procedures are inadequate or that the CEMS or sorbent trap monitoring system is incapable of providing quality data. Therefore, whenever excessive inaccuracies occur for two consecutive quarters, the source owner or operator must revise the QC procedures (*see* section 3) or modify, repair, or replace the CEMS or sorbent trap monitoring system.

6.0 Reporting Requirements

6.1 Data Assessment Report. At the reporting interval specified in the applicable regulation or permit, report for each Hg CEMS and/or sorbent trap monitoring system the accuracy assessment results from section 5, above. For Hg CEMS, also report the CD assessment results from section 4, above. Report this information as a Data Assessment Report (DAR), and include the appropriate DAR(s) with the emissions report required under the applicable regulation or permit.

6.2 Contents of the DAR. At a minimum, the DAR must contain the following information:

6.2.1 Facility name and address including identification of source owner/operator.

6.2.2 Identification and location of each Hg CEMS and/or sorbent trap monitoring system.

6.2.3 Manufacturer, model, and serial number of each Hg CEMS and/or sorbent trap monitoring system.

6.2.4 CD Assessment for each Hg CEMS, including the identification of out-of-control periods.

6.2.5 System integrity check data for each Hg CEMS.

6.2.6 Accuracy assessment for each Hg CEMS and/or sorbent trap monitoring system, including the identification of out-of-control periods. The results of all required RATAs, QGAs, RAAs, and audits of auxiliary equipment must be reported. If an accuracy audit shows a CEMS or sorbent trap monitoring system to be out-of-control, report both the audit results that caused the out-of-control period and the results of the retest following corrective action, showing the monitoring system to be operating within specifications.

6.2.7 Summary of all corrective actions taken when the Hg CEMS and/or sorbent trap monitoring system was determined to be out-of-control.

6.3 Data Retention. As required in 40 CFR 60.7(d) and 63.10(b), all measurements from CEMS and sorbent trap monitoring systems, including the quality assurance data required by this procedure, must be retained by the source owner for at least 5 years.

7.0 Bibliography

7.1 Calculation and Interpretation of Accuracy for Continuous Emission Monitoring Systems (CEMS). section 3.0.7 of the Quality Assurance Handbook for Air Pollution Measurement Systems, Volume III, Stationary Source Specific Methods. EPA-600/4-77-027b. August 1977. U.S. Environmental Protection Agency. Office of Research and Development Publications, 26 West St. Clair Street, Cincinnati, OH 45268.

Procedure 6. Quality Assurance Requirements for Gaseous Hydrogen Chloride (HCl) Continuous Emission Monitoring Systems Used for Compliance Determination at Stationary Sources

1.0 Applicability and Principle

1.1 Applicability. Procedure 6 is used to evaluate the effectiveness of quality control (QC) and quality assurance (QA) procedures and evaluate the quality of data produced by any hydrogen chloride (HCl) gas, CAS: 7647-01-0, continuous emission monitoring system (CEMS) that is used for determining compliance with emission standards for HCl on a continuous basis as specified in an applicable permit or regulation.

1.1.1 This procedure specifies the minimum QA requirements necessary for the control and assessment of the quality of CEMS data submitted to the Environmental Protection Agency (EPA) or a delegated authority. If you are responsible for one or more CEMS used for HCl compliance monitoring you must meet these minimum requirements and you are encouraged to develop and implement a more extensive QA program or to continue such programs where they already exist.

1.1.2 Data collected as a result of QA and QC measures required in this procedure are to be submitted to the EPA or the delegated authority in accordance with the applicable regulation or permit. These data are to be used by both the delegated authority and you, as the CEMS operator, in assessing the effectiveness of the CEMS QC and QA procedures in the maintenance of acceptable CEMS operation and valid emission data.

1.2 Principle

1.2.1 The QA procedures consist of two distinct and equally important functions. One function is the assessment of the quality of the CEMS data by estimating accuracy. The other function is the control and improvement of the quality of the CEMS data by implementing QC policies and corrective actions. These two functions form an iterative control loop. When the assessment function indicates that the data quality is inadequate, the control effort must be increased until the data quality is acceptable. In order to provide uniformity in the assessment and reporting of data quality, this procedure specifies the assessment procedures to evaluate response drift and accuracy. The procedures specified are based on Performance Specification 18 (PS-18) in appendix B to this part.

(Note: Because the control and corrective action function encompasses a variety of policies, specifications, standards and corrective measures, this procedure treats QC requirements in general terms to allow you, as source owner or operator to develop the most effective and efficient QC system for your circumstances.)

2.0 Definitions

See PS-18 of this subpart for the primary definitions used in this Procedure.

3.0 QC Requirements

3.1 You, as a source owner or operator, must develop and implement a QC program. At a minimum, each QC program must include written procedures and/or manufacturer's information which should describe in detail, complete, step-by-step procedures and operations for each of the following activities:

(a) Calibration Drift (CD) checks of CEMS;

(b) CD determination and adjustment of CEMS;

(c) Integrated Path (IP) CEMS temperature and pressure sensor accuracy checks;

(d) IP CEMS beam intensity checks;

(e) Routine and preventative maintenance of CEMS (including spare parts inventory);

(f) Data recording, calculations, and reporting;

(g) Accuracy audit procedures for CEMS including reference method(s); and

(h) Program of corrective action for malfunctioning CEMS.

3.2 These written procedures must be kept on site and available for inspection by the delegated authority. As described in section 5.4, whenever excessive inaccuracies occur for two consecutive quarters, you must revise the current written procedures, or modify or replace the CEMS to correct the deficiency causing the excessive inaccuracies.

4.0 Daily Data Quality Requirements and Measurement Standardization Procedures

4.1 CD Assessment. An upscale gas, used to meet a requirement in this section must be either a NIST-traceable reference gas or a gas certified by the gas vendor to ±5.0 percent accuracy.

4.1.1 CD Requirement. Consistent with 40 CFR 60.13(d) and 63.8(c), you, as source owners or operators of CEMS must check, record, and quantify the CD at two levels, using a zero gas and mid-level gas at least once daily (approximately every 24 hours). Perform the CD check in accordance with the procedure in applicable performance specification (*e.g.,* section 11.8 of PS-18 in appendix B of this part). The daily zero- and mid-level CD must not exceed two times the drift limits specified in the applicable performance specification (*e.g.,* section 13.2 of PS-18 in appendix B to this part.)

4.1.2 Recording Requirement for CD Corrective action. Corrective actions taken to bring a CEMS back in control after exceeding a CD limit must be recorded and reported with the associated CEMS data. Reporting corrective action must include the unadjusted concentration measured prior to resetting the calibration and the adjusted value after resetting the calibration to bring the CEMS back into control.

4.1.3 Dynamic Spiking Option for Mid-level CD. For extractive CEMS, you have the option to conduct a daily dynamic spiking procedure found in section 11.8.8 of PS-18 of appendix B of this part in lieu of the daily mid-level CD check. If this option is selected, the daily zero CD check is still required.

4.1.4 Out of Control Criteria for Excessive CD. As specified in §63.8(c)(7)(i)(A), a CEMS is out of control if the zero or mid-level CD exceeds two times the applicable CD specification in the applicable PS or in the relevant standard. When a CEMS is out of control, you as owner or operator of the affected source must take the necessary corrective actions and repeat the tests that caused the system to go out of control (in this case, the failed CD check) until the applicable performance requirements are met.

4.1.5 Additional Quality Assurance for Data above Span. This procedure must be used when required by an applicable regulation and may be used when significant data above span are being collected. Furthermore, the terms of this procedure do not apply to the extent that alternate terms are otherwise specified in an applicable rule or permit.

4.1.5.1 Any time the average measured concentration of HCl exceeds 150 percent of the span value for two consecutive one-hour averages, conduct the following 'above span' CEMS response check.

4.1.5.1.1 Within a period of 24 hours (before or after) of the 'above span' period, introduce a higher, 'above span' HCl reference gas standard to the CEMS. Use 'above span' reference gas that meets the requirements of section 7.0 of PS-18 and target a concentration level between 75 and 125 percent of the highest hourly concentration measured during the period of measurements above span.

4.1.5.1.2 Introduce the reference gas at the probe for extractive CEMS or for IP-CEMS as an equivalent path length corrected concentration in the instrument calibration cell.

4.1.5.1.3 At no time may the 'above span' concentration exceed the analyzer full-scale range.

4.1.5.2 Record and report the results of this procedure as you would for a daily calibration. The 'above span' response check is successful if the value measured by the CEMS is within 20 percent of the certified value of the reference gas.

4.1.5.3 If the 'above span' response check is conducted during the period when measured emissions are above span and there is a failure to collect at least one data point in an hour due to the response check duration, then determine the emissions average for that missed hour as the average of hourly averages for the hour preceding the missed hour and the hour following the missed hour.

4.1.5.4 In the event that the 'above span' response check is not successful (*i.e.,* the CEMS measured value is not within 20 percent of the certified value of the reference gas), then you must normalize the one-hour average stack gas values measured above the span during the 24-hour period preceding or following the 'above span' response check for reporting based on the CEMS response to the reference gas as shown in Eq. 6-1:

$$\text{Normalized stack gas result} = \frac{\text{Certified reference gas value}}{\text{Measured value of reference gas}} \times \text{Measured stack gas result} \qquad \text{Eq.6-1}$$

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4.2 Beam Intensity Requirement for HCl IP-CEMS.

4.2.1 Beam Intensity Measurement. If you use a HCl IP-CEMS, you must quantify and record the beam intensity of the IP-CEMS in appropriate units at least once daily (approximately 24 hours apart) according to manufacturer's specifications and procedures.

4.2.2 Out of Control Criteria for Excessive Beam Intensity Loss. If the beam intensity falls below the level established for the operation range determined following the procedures in section 11.2 of PS-18 of this part, then your CEMS is out-of-control. This quality check is independent of whether the CEMS daily CD is acceptable. If your CEMS is out-of-control, take necessary corrective action. You have the option to repeat the beam intensity test procedures in section 11.2 of PS-18 to expand the acceptable range of acceptable beam intensity. Following corrective action, repeat the beam intensity check.

4.3 Out Of Control Period Duration for Daily Assessments. The beginning of the out-of-control period is the hour in which the owner or operator conducts a daily performance check (*e.g.,* calibration drift or beam intensity check) that indicates an exceedance of the performance requirements established under this procedure. The end of the out-of-control period is the completion of daily assessment of the same type following corrective actions, which shows that the applicable performance requirements have been met.

4.4 CEMS Data Status During Out-of-Control Period. During the period the CEMS is out-of-control, the CEMS data may not be used in calculating compliance with an emissions limit nor be counted towards meeting minimum data availability as required and described in the applicable regulation or permit.

5.0 Data Accuracy Assessment

You must audit your CEMS for the accuracy of HCl measurement on a regular basis at the frequency described in this section, unless otherwise specified in an applicable regulation or permit. Quarterly audits are performed at least once each calendar quarter. Successive quarterly audits, to the extent practicable, shall occur no closer than 2 months apart. Annual audits are performed at least once every four consecutive calendar quarters.

5.1 Temperature and Pressure Accuracy Assessment for IP CEMS.

5.1.1 Stack or source gas temperature measurement audits for HCl IP-CEMS must be conducted and recorded at least annually in accordance with the procedure described in section 11.3 of PS-18 in appendix B to this part. As an alternative, temperature measurement devices may be replaced with certified instruments on an annual basis. Units removed from service may be bench tested against an NIST traceable sensor and reused during subsequent years. Any measurement instrument or device that is used to conduct ongoing verification of temperature measurement must have an accuracy that is traceable to NIST.

5.1.2 Stack or source gas pressure measurement audits for HCl IP-CEMS must be conducted and recorded at least annually in accordance with the procedure described in section 11.4 of PS-18 in appendix B of this part. As an alternative, pressure measurement devices may be replaced with certified instruments on an annual basis. Units removed from service may be bench tested against an NIST traceable sensor and reused during subsequent years. Any measurement instrument or device that is used to conduct ongoing verification of pressure measurement must have an accuracy that is traceable to NIST.

5.1.3 Out of Control Criteria for Excessive Parameter Verification Inaccuracy. If the temperature or pressure verification audit exceeds the criteria in sections 5.3.4.5 and 5.3.4.6, respectively, the CEMS is out-of-control. If the CEMS is out-of-control, take necessary corrective action to eliminate the problem. Following corrective action, you must repeat the failed verification audit until the temperature or pressure measurement device is operating within the applicable specifications, at which point the out-of-control period ends.

5.2 Concentration Accuracy Auditing Requirements. Unless otherwise specified in an applicable rule or permit, you must audit the HCl measurement accuracy of each CEMS at least once each calendar quarter, except in the case where the affected facility is off-line (does not operate). In that case, the audit must be performed as soon as is practicable in the quarter in which the unit recommences operation. Successive quarterly audits must, to the extent practicable, be performed no less than 2 months apart. The accuracy audits shall be conducted as follows:

5.2.1 Relative Accuracy Test Audit. A RATA must be conducted at least once every four calendar quarters, except as otherwise noted in sections 5.2.5 or 5.5 of this procedure. Perform the RATA as described in section 11.9 of PS-18 in appendix B to this part. If the HCl concentration measured by the RM during a RATA (in ppmv) is less than or equal to 20 percent of the concentration equivalent to the applicable emission standard, you must perform a Cylinder Gas Audit (CGA) or a Dynamic Spike Audit (DSA) for at least one subsequent (one of the following three) quarterly accuracy audits.

5.2.2 Quarterly Relative Accuracy Audit (RAA). A quarterly RAA may be conducted as an option to conducting a RATA in three of four calendar quarters, but in no more than three quarters in succession. To conduct an RAA, follow the test procedures in section 11.9 of PS-18 in appendix B to this part, except that only three test runs are required. The difference between the mean of the RM values and the mean of the CEMS responses relative to the mean of the RM values (or alternatively the emission standard) is used to assess the accuracy of the CEMS. Calculate the RAA results as described in section 6.2. As an alternative to an RAA, a cylinder gas audit or a dynamic spiking audit may be conducted.

5.2.3 Cylinder Gas Audit. A quarterly CGA may be conducted as an option to conducting a RATA in three of four calendar quarters, but in no more than three consecutive quarters. To perform a CGA, challenge the CEMS with a zero-level and two upscale level audit gases of known concentrations within the following ranges:

Audit point	Audit range
1 (Mid-Level)	50 to 60% of span value.
2 (High-Level)	80 to 100% of span value.

5.2.3.1 Inject each of the three audit gases (zero and two upscale) three times each for a total of nine injections. Inject the gases in such a manner that the entire CEMS is challenged. Do not inject the same gas concentration twice in succession.

5.2.3.2 Use HCl audit gases that meet the requirements of section 7 of PS-18 in appendix B to this part.

5.2.3.3 Calculate results as described in section 6.3.

5.2.4 Dynamic Spiking Audit. For extractive CEMS, a quarterly DSA may be conducted as an option to conducting a RATA in three of four calendar quarters, but in no more than three quarters in succession.

5.2.4.1 To conduct a DSA, you must challenge the entire HCl CEMS with a zero gas in accordance with the procedure in section 11.8 of PS-18 in appendix B of this part. You must also conduct the DS procedure as described in appendix A to PS-18 of appendix B to this part. You must conduct three spike injections with each of two upscale level audit gases. The upscale level gases must meet the requirements of section 7 of PS-18 in appendix B to this part and must be chosen to yield concentrations at the analyzer of 50 to 60 percent of span and 80 to 100 percent of span. Do not inject the same gas concentration twice in succession.

5.2.4.2 Calculate results as described in section 6.4. To determine CEMS accuracy, you must calculate the dynamic spiking error (DSE) for each of the two upscale audit gases using Equation A5 in appendix A to PS-18 and Equation 6-3 in section 6.4 of Procedure 6 in appendix B to this part.

5.2.5 Other Alternative Quarterly Audits. Other alternative audit procedures, as approved by the Administrator, may be used for three of four calendar quarters.

5.3 Out of Control Criteria for Excessive Audit Inaccuracy. If the results of the RATA, RAA, CGA, or DSA do not meet the applicable performance criteria in section 5.3.4, the CEMS is out-of-control. If the CEMS is out-of-control, take necessary corrective action to eliminate the problem. Following corrective action, the CEMS must pass a test of the same type that resulted in the out-of-control period to determine if the CEMS is operating within the specifications (*e.g.,* a RATA must always follow an out-of-control period resulting from a RATA).

5.3.1 If the audit results show the CEMS to be out-of-control, you must report both the results of the audit showing the CEMS to be out-of-control and the results of the audit following corrective action showing the CEMS to be operating within specifications.

5.3.2 Out-Of-Control Period Duration for Excessive Audit Inaccuracy. The beginning of the out-of-control period is the time corresponding to the completion of the sampling for the failed RATA, RAA, CGA or DSA. The end of the out-of-control period is the time corresponding to the completion of the sampling of the subsequent successful audit.

5.3.3 CEMS Data Status During Out-Of-Control Period. During the period the CEMS is out-of-control, the CEMS data may not be used in calculating emission compliance nor be counted towards meeting minimum data availability as required and described in the applicable regulation or permit.

5.3.4 Criteria for Excessive Quarterly and Yearly Audit Inaccuracy. Unless specified otherwise in the applicable regulation or permit, the criteria for excessive inaccuracy are:

5.3.4.1 For the RATA, the CEMS must meet the RA specifications in section 13.4 of PS-18 in appendix B to this part.

5.3.4.2 For the CGA, the accuracy must not exceed 5.0 percent of the span value at the zero gas and the mid- and high-level reference gas concentrations.

5.3.4.3 For the RAA, the RA must not exceed 20.0 percent of the RM_{avg} as calculated using Equation 6-2 in section 6.2 of this procedure whether calculated in units of HCl concentration or in units of the emission standard. In cases where the RA is calculated on a concentration (ppmv) basis, if the average HCl concentration measured by the RM during the test is less than 75 percent of the HCl concentration equivalent to the applicable standard, you may substitute the equivalent emission standard value (in ppmvw) in the denominator of Equation 6-2 in the place of RM_{avg} and the result of this alternative calculation of RA must not exceed 15.0 percent.

5.3.4.4 For DSA, the accuracy must not exceed 5.0 percent of the span value at the zero gas and the mid- and high-level reference gas concentrations or 20.0 percent of the applicable emission standard, whichever is greater.

5.3.4.5 For the gas temperature measurement audit, the CEMS must satisfy the requirements in section 13.7 in PS-18 of appendix B to this part.

5.3.4.6 For the gas pressure measurement audit, the CEMS must satisfy the requirements in section 13.8 in PS-18 of appendix B to this part.

5.4 Criteria for Acceptable QC Procedures. Repeated excessive inaccuracies (*i.e.,* out-of-control conditions resulting from the quarterly or yearly audits) indicate that the QC procedures are inadequate or that the CEMS is incapable of providing quality data. Therefore, whenever excessive inaccuracies occur for two consecutive quarters, you must revise the QC procedures (see section 3.0) or modify or replace the CEMS.

5.5 Criteria for Optional QA Test Frequency. If all the quality criteria are met in sections 4 and 5 of this procedure, the CEMS is in-control.

5.5.1 Unless otherwise specified in an applicable rule or permit, if the CEMS is in-control and if your source emits ≤75 percent of the HCl emission limit for each averaging period as specified in the relevant standard for eight consecutive quarters that include a minimum of two RATAs, you may revise your auditing procedures to use CGA, RAA or DSA each quarter for seven subsequent quarters following a RATA.

5.5.2 You must perform at least one RATA that meets the acceptance criteria every 2 years.

5.5.3 If you fail a RATA, RAA, CGA, or DSA, then the audit schedule in section 5.2 must be followed until the audit results meet the criteria in section 5.3.4 to start requalifying for the optional QA test frequency in section 5.5.

6.0 Calculations for CEMS Data Accuracy

6.1 RATA RA Calculation. Follow Equations 9 through 14 in section 12 of PS-18 in appendix B to this part to calculate the RA for the RATA. The RATA must be calculated either in units of the applicable emission standard or in concentration units (ppmv).

6.2 RAA Accuracy Calculation. Use Equation 6-2 to calculate the accuracy for the RAA. The RA may be calculated in concentration units (ppmv) or in the units of the applicable emission standard.

$$RA = \frac{[MN_{avg} - RM_{avg}]}{RM_{avg}} * 100 \text{ Eq.} \qquad \text{Eq. 6-2}$$

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Where:

RA = Accuracy of the CEMS (percent)

MN_{avg} = Average measured CEMS response during the audit in units of applicable standard or appropriate concentration.

RM_{avg} = Average reference method value in units of applicable standard or appropriate concentration.

6.3 CGA Accuracy Calculation. For each gas concentration, determine the average of the three CEMS responses and subtract the average response from the audit gas value. For extractive CEMS, calculate the ME at each gas level using Equation 3A in section 12.3 of PS-18 in appendix B to this part. For IP-CEMS, calculate the ME at each gas level using Equation 6A in section 12.4.3 of PS-18 in appendix B to this part.

6.4 DSA Accuracy Calculation. DSA accuracy is calculated as a percent of span. To calculate the DSA accuracy for each upscale spike concentration, first calculate the DSE using Equation A5 in appendix A of PS-18 in appendix B to this part. Then use Equation 6-3 to calculate the average DSA accuracy for each upscale spike concentration. To calculate DSA accuracy at the zero level, use equation 3A in section 12.3 of PS-18 in appendix B to this part.

$$DSA\ Accuracy = \frac{\sum_{1}^{3}\left|\frac{|DSE_i|}{S}\right|}{3} * 100 \qquad \text{Eq. 6-3}$$

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7.0 Reporting Requirements

At the reporting interval specified in the applicable regulation or permit, report for each CEMS the quarterly and annual accuracy audit results from section 6 and the daily assessment results from section 4. Unless otherwise specified in the applicable regulation or permit, include all data sheets, calculations, CEMS data records (*i.e.,* charts, records of CEMS responses), reference gas certifications and reference method results necessary to confirm that the performance of the CEMS met the performance specifications.

7.1 Unless otherwise specified in the applicable regulations or permit, report the daily assessments (CD and beam intensity) and accuracy audit information at the interval for emissions reporting required under the applicable regulations or permits.

7.1.1 At a minimum, the daily assessments and accuracy audit information reporting must contain the following information:

a. Company name and address.

b. Identification and location of monitors in the CEMS.

c. Manufacturer and model number of each monitor in the CEMS.

d. Assessment of CEMS data accuracy and date of assessment as determined by a RATA, RAA, CGA or DSA described in section 5 including:

i. The RA for the RATA;

ii. The accuracy for the CGA, RAA, or DSA;

iiii. Temperature and pressure sensor audit results for IP-CEMS;

iv. The RM results, the reference gas certified values;

v. The CEMS responses;

vi. The calculation results as defined in section 6; and

vii. Results from the performance audit samples described in section 5 and the applicable RMs.

e. Summary of all out-of-control periods including corrective actions taken when CEMS was determined out-of-control, as described in sections 4 and 5.

7.1.2 If the accuracy audit results show the CEMS to be out-of-control, you must report both the audit results showing the CEMS to be out-of-control and the results of the audit following corrective action showing the CEMS to be operating within specifications.

8.0 Bibliography

1. EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards, U.S. Environmental Protection Agency office of Research and Development, EPA/600/R-12/531, May 2012.

2. Method 205, "Verification of Gas Dilution Systems for Field Instrument Calibrations," 40 CFR part 51, appendix M.

9.0 Tables, Diagrams, Flowcharts [Reserved]

[52 FR 21008, June 4, 1987; 52 FR 27612, July 22, 1987, as amended at 56 FR 5527, Feb. 11, 1991; 69 FR 1816, Jan. 12, 2004; 72 FR 32768, June 13, 2007; 74 FR 12590, Mar. 25, 2009; 75 FR 55040, Sept. 9, 2010; 79 FR 11274, Feb. 27, 2014; 79 FR 28441, May 16, 2014; 80 FR 38649, July 7, 2015; 81 FR 59824, Aug. 30, 2016; 82 FR 37824, Aug. 14, 2017; 82 FR 44108, Sept. 21, 2017; 83 FR 56725, Nov. 14, 2018]

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ELECTRONIC CODE OF FEDERAL REGULATIONS

e-CFR data is current as of May 13, 2019

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Title 40: Protection of Environment
PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES
Subpart A—General Provisions

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§60.13 Monitoring requirements.

(a) For the purposes of this section, all continuous monitoring systems required under applicable subparts shall be subject to the provisions of this section upon promulgation of performance specifications for continuous monitoring systems under appendix B to this part and, if the continuous monitoring system is used to demonstrate compliance with emission limits on a continuous basis, appendix F to this part, unless otherwise specified in an applicable subpart or by the Administrator. Appendix F is applicable December 4, 1987.

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

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

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

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

(d)(1) Owners and operators of a CEMS installed in accordance with the provisions of this part, must check the zero (or low level value between 0 and 20 percent of span value) and span (50 to 100 percent of span value) calibration drifts at least once each operating day in accordance with a written procedure. The zero and span must, at a minimum, be adjusted whenever either the 24-hour zero drift or the 24-hour span drift exceeds two times the limit of the applicable performance specification in appendix B of this part. The system must allow the amount of the excess zero and span drift to be recorded and quantified whenever specified. Owners and operators of a COMS installed in accordance with the provisions of this part must check the zero and upscale (span) calibration drifts at least once daily. For a particular COMS, the acceptable range of zero and upscale calibration materials is defined in the applicable version of PS-1 in appendix B of this part. For a COMS, the optical surfaces, exposed to the effluent gases, must be cleaned before performing the zero and upscale drift adjustments, except for systems using automatic zero adjustments. The optical surfaces must be cleaned when the cumulative automatic zero compensation exceeds 4 percent opacity.

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

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

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

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

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

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

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

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

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

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

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

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

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

(iv) If a daily calibration error check is failed during any operating hour, all data for that hour shall be invalidated, unless a subsequent calibration error test is passed in the same hour and the requirements of paragraph (h)(2)(iii) of this section are met, based solely on valid data recorded after the successful calibration.

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

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

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

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

(ix) Either arithmetic or integrated averaging of all data may be used to calculate the hourly averages. The data may be recorded in reduced or nonreduced form (e.g., ppm pollutant and percent O_2 or ng/J of pollutant).

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

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

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

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

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

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

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

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

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

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

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

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

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

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

days of such occurrence and include a description of the nature and cause of the increasing emissions. The Administrator will review the notification and may rescind the waiver and require the owner or operator to conduct a RA test of the CEMS as specified in Section 8.4 of Performance Specification 2.

[40 FR 46255, Oct. 6, 1975]

EDITORIAL NOTE: For FEDERAL REGISTER citations affecting §60.13, see the List of CFR Sections Affected, which appears in the Finding Aids section of the printed volume and at *www.govinfo.gov.*

ELECTRONIC CODE OF FEDERAL REGULATIONS

e-CFR data is current as of May 13, 2019

Title 40: Protection of Environment
PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES
Subpart Db—Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

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§60.46b Compliance and performance test methods and procedures for particulate matter and nitrogen oxides.

(a) The PM emission standards and opacity limits under §60.43b apply at all times except during periods of startup, shutdown, or malfunction. The NO_X emission standards under §60.44b apply at all times.

(b) Compliance with the PM emission standards under §60.43b shall be determined through performance testing as described in paragraph (d) of this section, except as provided in paragraph (i) of this section.

(c) Compliance with the NO_X emission standards under §60.44b shall be determined through performance testing under paragraph (e) or (f), or under paragraphs (g) and (h) of this section, as applicable.

(d) To determine compliance with the PM emission limits and opacity limits under §60.43b, the owner or operator of an affected facility shall conduct an initial performance test as required under §60.8, and shall conduct subsequent performance tests as requested by the Administrator, using the following procedures and reference methods:

(1) Method 3A or 3B of appendix A-2 of this part is used for gas analysis when applying Method 5 of appendix A-3 of this part or Method 17 of appendix A-6 of this part.

(2) Method 5, 5B, or 17 of appendix A of this part shall be used to measure the concentration of PM as follows:

(i) Method 5 of appendix A of this part shall be used at affected facilities without wet flue gas desulfurization (FGD) systems; and

(ii) Method 17 of appendix A-6 of this part may be used at facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a 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 a wet FGD system. Do not use Method 17 of appendix A-6 of this part after wet FGD systems if the effluent is saturated or laden with water droplets.

(iii) Method 5B of appendix A of this part is to be used only after wet FGD systems.

(3) Method 1 of appendix A of this part is used to select the sampling site and the number of traverse sampling points. The sampling time for each run is at least 120 minutes and the minimum sampling volume is 1.7 dscm (60 dscf) except that smaller sampling times or volumes may be approved by the Administrator when necessitated by process variables or other factors.

(4) For Method 5 of appendix A of this part, the temperature of the sample gas in the probe and filter holder is monitored and is maintained at 160±14 °C (320±25 °F).

(5) For determination of PM emissions, the oxygen (O_2) or CO_2 sample is obtained simultaneously with each run of Method 5, 5B, or 17 of appendix A of this part by traversing the duct at the same sampling location.

(6) For each run using Method 5, 5B, or 17 of appendix A of this part, the emission rate expressed in ng/J heat input is determined using:

(i) The O_2 or CO_2 measurements and PM measurements obtained under this section;

(ii) The dry basis F factor; and

(iii) The dry basis emission rate calculation procedure contained in Method 19 of appendix A of this part.

(7) Method 9 of appendix A of this part is used for determining the opacity of stack emissions.

(e) To determine compliance with the emission limits for NO_X required under §60.44b, the owner or operator of an affected facility shall conduct the performance test as required under §60.8 using the continuous system for monitoring NO_X under §60.48(b).

(1) For the initial compliance test, NO_X from the steam generating unit are monitored for 30 successive steam generating unit operating days and the 30-day average emission rate is used to determine compliance with the NO_X emission standards under §60.44b. The 30-day average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 30-day test period.

(2) Following the date on which the initial performance test is completed or is required to be completed in §60.8, whichever date comes first, the owner or operator of an affected facility which combusts coal (except as specified under §60.46b(e)(4)) or which combusts residual oil having a nitrogen content greater than 0.30 weight percent shall determine compliance with the NO_X emission standards in §60.44b on a continuous basis through the use of a 30-day rolling average emission rate. A new 30-day rolling average emission rate is calculated for each steam generating unit operating day as the average of all of the hourly NO_X emission data for the preceding 30 steam generating unit operating days.

(3) Following the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility that has a heat input capacity greater than 73 MW (250 MMBtu/hr) and that combusts natural gas, distillate oil, or residual oil having a nitrogen content of 0.30 weight percent or less shall determine compliance with the NO_X standards under §60.44b on a continuous basis through the use of a 30-day rolling average emission rate. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly NO_X emission data for the preceding 30 steam generating unit operating days.

(4) Following 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 affected facility that has a heat input capacity of 73 MW (250 MMBtu/hr) or less and that combusts natural gas, distillate oil, gasified coal, or residual oil having a nitrogen content of 0.30 weight percent or less shall upon request determine compliance with the NO_X standards in §60.44b through the use of a 30-day performance test. During periods when performance tests are not requested, NO_X emissions data collected pursuant to §60.48b(g)(1) or §60.48b(g)(2) are used to calculate a 30-day rolling average emission rate on a daily basis and used to prepare excess emission reports, but will not be used to determine compliance with the NO_X emission standards. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly NO_X emission data for the preceding 30 steam generating unit operating days.

(5) If the owner or operator of an affected facility that combusts residual oil does not sample and analyze the residual oil for nitrogen content, as specified in §60.49b(e), the requirements of §60.48b(g)(1) apply and the provisions of §60.48b(g)(2) are inapplicable.

(f) To determine compliance with the emissions limits for NO_X required by §60.44b(a)(4) or §60.44b(l) for duct burners used in combined cycle systems, either of the procedures described in paragraph (f)(1) or (2) of this section may be used:

(1) The owner or operator of an affected facility shall conduct the performance test required under §60.8 as follows:

(i) The emissions rate (E) of NO_X shall be computed using Equation 1 in this section:

$$E = E_{sg} + \left(\frac{H_g}{H_b}\right)(E_{sg} - E_g) \qquad \text{(Eq.1)}$$

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Where:

E = Emissions rate of NO_X from the duct burner, ng/J (lb/MMBtu) heat input;

E_{sg} = Combined effluent emissions rate, in ng/J (lb/MMBtu) heat input using appropriate F factor as described in Method 19 of appendix A of this part;

H_g = Heat input rate to the combustion turbine, in J/hr (MMBtu/hr);

H_b = Heat input rate to the duct burner, in J/hr (MMBtu/hr); and

E_g = Emissions rate from the combustion turbine, in ng/J (lb/MMBtu) heat input calculated using appropriate F factor as described in Method 19 of appendix A of this part.

(ii) Method 7E of appendix A of this part or Method 320 of appendix A of part 63 shall be used to determine the NO_X concentrations. Method 3A or 3B of appendix A of this part shall be used to determine O_2 concentration.

(iii) The owner or operator shall identify and demonstrate to the Administrator's satisfaction suitable methods to determine the average hourly heat input rate to the combustion turbine and the average hourly heat input rate to the affected duct burner.

(iv) Compliance with the emissions limits under §60.44b(a)(4) or §60.44b(l) is determined by the three-run average (nominal 1-hour runs) for the initial and subsequent performance tests; or

(2) The owner or operator of an affected facility may elect to determine compliance on a 30-day rolling average basis by using the CEMS specified under §60.48b for measuring NO_X and O_2 and meet the requirements of §60.48b. The sampling site shall be located at the outlet from the steam generating unit. The NO_X emissions rate at the outlet from the steam generating unit shall constitute the NO_X emissions rate from the duct burner of the combined cycle system.

(g) The owner or operator of an affected facility described in §60.44b(j) or §60.44b(k) shall demonstrate the maximum heat input capacity of the steam generating unit by operating the facility at maximum capacity for 24 hours. The owner or operator of an affected facility shall determine the maximum heat input capacity using the heat loss method or the heat input method described in sections 5 and 7.3 of the ASME *Power Test Codes* 4.1 (incorporated by reference, see §60.17). This demonstration of maximum heat input capacity shall be made during the initial performance test for affected facilities that meet the criteria of §60.44b(j). It shall be made 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 start-up of each facility, for affected facilities meeting the criteria of §60.44b(k). Subsequent demonstrations may be required by the Administrator at any other time. If this demonstration indicates that the maximum heat input capacity of the affected facility is less than that stated by the manufacturer of the affected facility, the maximum heat input capacity determined during this demonstration shall be used to determine the capacity utilization rate for the affected facility. Otherwise, the maximum heat input capacity provided by the manufacturer is used.

(h) The owner or operator of an affected facility described in §60.44b(j) that has a heat input capacity greater than 73 MW (250 MMBtu/hr) shall:

(1) Conduct an initial performance test as required under §60.8 over a minimum of 24 consecutive steam generating unit operating hours at maximum heat input capacity to demonstrate compliance with the NO_X emission standards under §60.44b using Method 7, 7A, or 7E of appendix A of this part, Method 320 of appendix A of part 63 of this chapter, or other approved reference methods; and

(2) Conduct subsequent performance tests once per calendar year or every 400 hours of operation (whichever comes first) to demonstrate compliance with the NO_X emission standards under §60.44b over a minimum of 3 consecutive steam generating unit operating hours at maximum heat input capacity using Method 7, 7A, or 7E of appendix A of this part, Method 320 of appendix A of part 63, or other approved reference methods.

(i) The owner or operator of an affected facility seeking to demonstrate compliance with the PM limit in paragraphs §60.43b(a)(4) or §60.43b(h)(5) shall follow the applicable procedures in §60.49b(r).

(j) In place of PM testing with Method 5 or 5B of appendix A-3 of this part, or Method 17 of appendix A-6 of this part, an owner or operator may elect to install, calibrate, maintain, and operate a CEMS for monitoring PM emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility who elects to continuously monitor PM emissions instead of conducting performance testing using Method 5 or 5B of appendix A-3 of this part or Method 17 of appendix A-6 of this part shall comply with the requirements specified in paragraphs (j)(1) through (j)(14) of this section.

(1) Notify the Administrator one month before starting use of the system.

(2) Notify the Administrator one month before stopping use of the system.

(3) The monitor shall be installed, evaluated, and operated in accordance with §60.13 of subpart A of this part.

(4) 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 notification to the Administrator of use of the CEMS if the owner or operator was previously determining compliance by Method 5, 5B, or 17 of appendix A of this part performance tests, whichever is later.

(5) The owner or operator of an affected facility shall conduct an initial performance test for PM emissions as required under §60.8 of subpart A of this part. Compliance with the PM emission limit shall be determined by using the CEMS specified in paragraph (j) of this section to measure PM and calculating a 24-hour block arithmetic average emission concentration using EPA Reference Method 19 of appendix A of this part, section 4.1.

(6) Compliance with the PM emission limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emission concentrations using CEMS outlet data.

(7) At a minimum, valid CEMS hourly averages shall be obtained as specified in paragraphs (j)(7)(i) of this section for 75 percent of the total operating hours per 30-day rolling average.

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

(ii) [Reserved]

(8) The 1-hour arithmetic averages required under paragraph (j)(7) of this section shall be expressed in ng/J or lb/MMBtu heat input 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.

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

(10) The CEMS shall be operated according to Performance Specification 11 in appendix B of this part.

(11) During the correlation testing runs 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 continuous emission monitors 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) For O_2 (or CO_2), Method 3A or 3B of appendix A-2 of this part, as applicable shall be used.

(12) 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.

(13) 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 75 percent of total operating hours per 30-day rolling average.

(14) As of January 1, 2012, and within 90 days after the date of completing each performance test, as defined in §60.8, conducted to demonstrate compliance with this subpart, you must submit relative accuracy test audit (*i.e.,* reference method) data and performance test (*i.e.,* compliance test) data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/ert_tool.html/*) or other compatible electronic spreadsheet. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5086, Jan. 28, 2009; 76 FR 3523, Jan. 20, 2011; 77 FR 9460, Feb. 16, 2012; 79 FR 11249, Feb. 27, 2014]

ELECTRONIC CODE OF FEDERAL REGULATIONS

e-CFR data is current as of May 13, 2019

Title 40: Protection of Environment
PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES
Subpart Db—Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

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§60.47b Emission monitoring for sulfur dioxide.

(a) Except as provided in paragraphs (b) and (f) of this section, the owner or operator of an affected facility subject to the SO_2 standards in §60.42b shall install, calibrate, maintain, and operate CEMS for measuring SO_2 concentrations and either O_2 or CO_2 concentrations and shall record the output of the systems. For units complying with the percent reduction standard, the SO_2 and either O_2 or CO_2 concentrations shall both be monitored at the inlet and outlet of the SO_2 control device. If the owner or operator has installed and certified SO_2 and O_2 or CO_2 CEMS 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, those CEMS may be used to meet the requirements of this section, provided that:

(1) When relative accuracy testing is conducted, SO_2 concentration data and CO_2 (or O_2) data are collected simultaneously; and

(2) 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

(3) The reporting requirements of §60.49b are met. SO_2 and CO_2 (or O_2) data used to meet the requirements of §60.49b 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_2 data have been bias adjusted according to the procedures of part 75 of this chapter.

(b) As an alternative to operating CEMS as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO_2 emissions and percent reduction by:

(1) Collecting coal or oil samples in an as-fired condition at the inlet to the steam generating unit and analyzing them for sulfur and heat content according to Method 19 of appendix A of this part. Method 19 of appendix A of this part provides procedures for converting these measurements into the format to be used in calculating the average SO_2 input rate, or

(2) Measuring SO_2 according to Method 6B of appendix A of this part at the inlet or outlet to the SO_2 control system. An initial stratification test is required to verify the adequacy of the sampling location for Method 6B of appendix A of this part. The stratification test shall consist of three paired runs of a suitable SO_2 and CO_2 measurement train operated at the candidate location and a second similar train operated according to the procedures in Section 3.2 and the applicable procedures in Section 7 of Performance Specification 2. Method 6B of appendix A of this part, Method 6A of appendix A of this part, or a combination of Methods 6 and 3 or 3B of appendix A of this part or Methods 6C or Method 320 of appendix A of part 63 of this chapter and 3A of appendix A of this part are suitable measurement techniques. If Method 6B of appendix A of this part is used for the second train, sampling time and timer operation may be adjusted for the stratification test as long as an adequate sample volume is collected; however, both sampling trains are to be operated similarly. For the location to be adequate for Method 6B of appendix A of this part, 24-hour tests, the mean of the absolute difference between the three paired runs must be less than 10 percent.

(3) A daily SO_2 emission rate, E_D, shall be determined using the procedure described in Method 6A of appendix A of this part, section 7.6.2 (Equation 6A-8) and stated in ng/J (lb/MMBtu) heat input.

(4) The mean 30-day emission rate is calculated using the daily measured values in ng/J (lb/MMBtu) for 30 successive steam generating unit operating days using equation 19-20 of Method 19 of appendix A of this part.

(c) The owner or operator of an affected facility shall obtain emission data for at least 75 percent of the operating hours in at least 22 out of 30 successive boiler operating days. If this minimum data requirement is not met with a single monitoring system, the owner or operator of the affected facility shall supplement the emission data with data collected with other monitoring systems as approved by the Administrator or the reference methods and procedures as described in paragraph (b) of this section.

(d) The 1-hour average SO_2 emission rates measured by the CEMS required by paragraph (a) of this section and required under §60.13(h) is expressed in ng/J or lb/MMBtu heat input and is used to calculate the average emission rates under §60.42(b). Each 1-hour average SO_2 emission rate must be based on 30 or more minutes of steam generating unit operation. The hourly averages shall be calculated according to §60.13(h)(2). Hourly SO_2 emission rates are not calculated if the affected facility is operated less than 30 minutes in a given clock hour and are not counted toward determination of a steam generating unit operating day.

(e) The procedures under §60.13 shall be followed for installation, evaluation, and operation of the CEMS.

(1) Except as provided for in paragraph (e)(4) of this section, all CEMS shall be operated in accordance with the applicable procedures under Performance Specifications 1, 2, and 3 of appendix B of this part.

(2) Except as provided for in paragraph (e)(4) of this section, quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with Procedure 1 of appendix F of this part.

(3) For affected facilities combusting coal or oil, alone or in combination with other fuels, the span value of the SO_2 CEMS at the inlet to the SO_2 control device is 125 percent of the maximum estimated hourly potential SO_2 emissions of the fuel combusted, and the span value of the CEMS at the outlet to the SO_2 control device is 50 percent of the maximum estimated hourly potential SO_2 emissions of the fuel combusted. Alternatively, SO_2 span values determined according to section 2.1.1 in appendix A to part 75 of this chapter may be used.

(4) As an alternative to meeting the requirements of requirements of paragraphs (e)(1) and (e)(2) of this section, the owner or operator may elect to implement the following alternative data accuracy assessment procedures:

(i) For all required CO_2 and O_2 monitors and for SO_2 and NO_X monitors 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 to this part.

(ii) For all required CO_2 and O_2 monitors and for SO_2 and NO_X monitors 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_X span values less than or equal to 30 ppm; and

(iii) For SO_2, CO_2, and O_2 monitoring systems and for NO_X emission rate monitoring systems, 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_2 emission level during the RATA), and for NO_X when the average NO_X emission rate measured by the reference method during the RATA is less than 0.100 lb/MMBtu.

(f) The owner or operator of an affected facility that combusts very low sulfur oil or is demonstrating compliance under §60.45b(k) is not subject to the emission monitoring requirements under paragraph (a) of this section if the owner or operator maintains fuel records as described in §60.49b(r).

[72 FR 32742, June 13, 2007, as amended at 74 FR 5087, Jan. 28, 2009; 79 FR 11249, Feb. 27, 2014]

ELECTRONIC CODE OF FEDERAL REGULATIONS

e-CFR data is current as of May 13, 2019

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PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES
Subpart Db—Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

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§60.48b Emission monitoring for particulate matter and nitrogen oxides.

(a) Except as provided in paragraph (j) of this section, the owner or operator of an affected facility subject to the opacity standard under §60.43b shall install, calibrate, maintain, and operate a continuous opacity monitoring systems (COMS) for measuring the opacity of emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility subject to an opacity standard under §60.43b and meeting the conditions under paragraphs (j)(1), (2), (3), (4), (5), or (6) of this section who elects not to use a COMS shall conduct a performance test using Method 9 of appendix A-4 of this part and the procedures in §60.11 to demonstrate compliance with the applicable limit in §60.43b by April 29, 2011, within 45 days of stopping use of an existing COMS, or within 180 days after initial startup of the facility, whichever is later, and shall comply with either paragraphs (a)(1), (a)(2), or (a)(3) of this section. The observation period for Method 9 of appendix A-4 of this part performance tests may be reduced from 3 hours to 60 minutes if all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent during the initial 60 minutes of observation.

(1) Except as provided in paragraph (a)(2) and (a)(3) 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) of this section according to the applicable schedule in paragraphs (a)(1)(i) through (a)(1)(iv) of this section, as determined by the most recent Method 9 of appendix A-4 of this part performance test results.

(i) 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 or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(ii) 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 or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(iii) 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 within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later; or

(iv) 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 45 calendar days from the date that the most recent performance test was conducted.

(2) 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)(2)(i) and (ii) of this section.

(i) 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) of this section within 45 calendar days according to the requirements in §60.46d(d)(7).

(ii) If no visible emissions are observed for 10 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.

(3) 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)(2) 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) Except as provided under paragraphs (g), (h), and (i) of this section, the owner or operator of an affected facility subject to a NO_X standard under §60.44b shall comply with either paragraphs (b)(1) or (b)(2) of this section.

(1) Install, calibrate, maintain, and operate CEMS for measuring NO_X and O_2 (or CO_2) emissions discharged to the atmosphere, and shall record the output of the system; or

(2) If the owner or operator has installed a NO_X emission 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 §60.49b. Data reported to meet the requirements of §60.49b 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.

(c) The CEMS required under paragraph (b) of this section shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

(d) The 1-hour average NO_X emission rates measured by the continuous NO_X monitor required by paragraph (b) of this section and required under §60.13(h) shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the average emission rates under §60.44b. The 1-hour averages shall be calculated using the data points required under §60.13(h)(2).

(e) The procedures under §60.13 shall be followed for installation, evaluation, and operation of the continuous monitoring systems.

(1) For affected facilities combusting coal, wood or municipal-type solid waste, the span value for a COMS shall be between 60 and 80 percent.

(2) For affected facilities combusting coal, oil, or natural gas, the span value for NO_X is determined using one of the following procedures:

(i) Except as provided under paragraph (e)(2)(ii) of this section, NO_X span values shall be determined as follows:

Fuel	**Span values for NO_X (ppm)**
Natural gas	500.
Oil	500.
Coal	1,000.
Mixtures	500 (x + y) + 1,000z.

Where:

x = Fraction of total heat input derived from natural gas;

y = Fraction of total heat input derived from oil; and

z = Fraction of total heat input derived from coal.

(ii) As an alternative to meeting the requirements of paragraph (e)(2)(i) of this section, the owner or operator of an affected facility may elect to use the NO_X span values determined according to section 2.1.2 in appendix A to part 75 of this chapter.

(3) All span values computed under paragraph (e)(2)(i) of this section for combusting mixtures of regulated fuels are rounded to the nearest 500 ppm. Span values computed under paragraph (e)(2)(ii) of this section shall be rounded off according to section 2.1.2 in appendix A to part 75 of this chapter.

(f) When NO_X emission data are not obtained because of CEMS breakdowns, repairs, calibration checks and zero and span adjustments, emission data will be obtained by using standby monitoring systems, Method 7 of appendix A of this part, Method 7A of appendix A of this part, or other approved reference methods to provide emission data for a minimum of 75 percent of the operating hours in each steam generating unit operating day, in at least 22 out of 30 successive steam generating unit operating days.

(g) The owner or operator of an affected facility that has a heat input capacity of 73 MW (250 MMBtu/hr) or less, and that has an annual capacity factor for residual oil having a nitrogen content of 0.30 weight percent or less, natural gas, distillate oil, gasified coal, or any mixture of these fuels, greater than 10 percent (0.10) shall:

(1) Comply with the provisions of paragraphs (b), (c), (d), (e)(2), (e)(3), and (f) of this section; or

(2) Monitor steam generating unit operating conditions and predict NO_X emission rates as specified in a plan submitted pursuant to §60.49b(c).

(h) The owner or operator of a duct burner, as described in §60.41b, that is subject to the NO_X standards in §60.44b(a)(4), §60.44b(e), or §60.44b(l) is not required to install or operate a continuous emissions monitoring system to measure NO_X emissions.

(i) The owner or operator of an affected facility described in §60.44b(j) or §60.44b(k) is not required to install or operate a CEMS for measuring NO_X emissions.

(j) The owner or operator of an affected facility that meets the conditions in either paragraph (j)(1), (2), (3), (4), (5), (6), or (7) of this section is not required to install or operate a COMS if:

(1) The affected facility uses a PM CEMS to monitor PM emissions; or

(2) The affected facility burns only liquid (excluding residual oil) or gaseous fuels with potential SO_2 emissions rates of 26 ng/J (0.060 lb/MMBtu) or less and does not use a post-combustion technology to reduce SO_2 or PM emissions. The owner or operator must maintain fuel records of the sulfur content of the fuels burned, as described under §60.49b(r); or

(3) The affected facility burns coke oven gas alone or in combination with fuels meeting the criteria in paragraph (j)(2) of this section and does not use a post-combustion technology to reduce SO_2 or PM emissions; or

(4) The affected facility does not use post-combustion technology (except a wet scrubber) for reducing PM, SO_2, or carbon monoxide (CO) emissions, burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur, and is operated such that emissions of CO to the atmosphere from the affected facility are maintained at levels less than or equal to 0.15 lb/MMBtu on a steam generating unit operating day average basis. Owners and operators of affected facilities electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (j)(4)(i) through (iv) of this section; or

(i) You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (j)(4)(i)(A) through (D) of this section.

(A) 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.

(B) 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).

(C) 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).

(D) 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.

(ii) You must calculate the 1-hour average CO emissions levels for each steam generating unit 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 heat input to the affected source. The 24-hour average CO emission level is determined by calculating the arithmetic average of the hourly CO emission levels computed for each steam generating unit operating day.

(iii) You must evaluate the preceding 24-hour average CO emission level each steam generating unit operating day excluding periods of affected source startup, shutdown, or malfunction. If the 24-hour average CO emission level is greater than 0.15 lb/MMBtu, 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 0.15 lb/MMBtu or less.

(iv) You must record the CO measurements and calculations performed according to paragraph (j)(4) 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 0.15 lb/MMBtu, and the date, time, and description of the corrective action.

(5) The affected facility uses a bag leak detection system to monitor the performance of a fabric filter (baghouse) according to the most current requirements in section §60.48Da of this part; or

(6) The affected facility uses an ESP as the primary PM control device and uses an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the most current requirements in section §60.48Da of this part; or

(7) The affected facility burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur and operates according to a written site-specific monitoring plan approved by the permitting authority. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard.

(k) Owners or operators complying with the PM emission limit by using a PM CEMS must calibrate, maintain, operate, and record the output of the system for PM emissions discharged to the atmosphere as specified in §60.46b(j). The CEMS specified in paragraph §60.46b(j) shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

(l) An owner or operator of an affected facility that is subject to an opacity standard under §60.43b(f) is not required to operate a COMS provided that the unit burns only gaseous fuels and/or liquid fuels (excluding residue oil) with a potential SO_2 emissions rate no greater than 26 ng/J (0.060 lb/MMBtu), and the unit operates according to a written site-specific monitoring plan approved by the permitting authority is not required to operate a COMS. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard. For testing performed as part of this site-specific monitoring plan, the permitting authority may require as an alternative to the notification and reporting requirements specified in §§60.8 and 60.11 that the owner or operator submit any deviations with the excess emissions report required under §60.49b(h).

[72 FR 32742, June 13, 2007, as amended at 74 FR 5087, Jan. 28, 2009; 76 FR 3523, Jan. 20, 2011; 77 FR 9460, Feb. 16, 2012]

ELECTRONIC CODE OF FEDERAL REGULATIONS

e-CFR data is current as of May 13, 2019

Title 40: Protection of Environment
PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES
Subpart Db—Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

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§60.49b Reporting and recordkeeping requirements.

(a) The owner or operator of each affected facility shall submit notification of the date of initial startup, as provided by §60.7. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of the fuels to be combusted in the affected facility;

(2) If applicable, a copy of any federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under §60.42b(d)(1), §60.43b(a)(2), (a)(3)(iii), (c)(2)(ii), (d)(2)(iii), §60.44b(c), (d), (e), (i), (j), (k), §60.45b(d), (g), §60.46b(h), or §60.48b(i);

(3) The annual capacity factor at which the owner or operator anticipates operating the facility based on all fuels fired and based on each individual fuel fired; and

(4) Notification that an emerging technology will be used for controlling emissions of SO_2. The Administrator will examine the description of the emerging technology and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of §60.42b(a) unless and until this determination is made by the Administrator.

(b) The owner or operator of each affected facility subject to the SO_2, PM, and/or NO_X emission limits under §§60.42b, 60.43b, and 60.44b shall submit to the Administrator the performance test data from the initial performance test and the performance evaluation of the CEMS using the applicable performance specifications in appendix B of this part. The owner or operator of each affected facility described in §60.44b(j) or §60.44b(k) shall submit to the Administrator the maximum heat input capacity data from the demonstration of the maximum heat input capacity of the affected facility.

(c) The owner or operator of each affected facility subject to the NO_X standard in §60.44b who seeks to demonstrate compliance with those standards through the monitoring of steam generating unit operating conditions in the provisions of §60.48b(g)(2) shall submit to the Administrator for approval a plan that identifies the operating conditions to be monitored in §60.48b(g)(2) and the records to be maintained in §60.49b(g). This plan shall be submitted to the Administrator for approval within 360 days of the initial startup of the affected facility. An affected facility burning coke oven gas alone or in combination with other gaseous fuels or distillate oil shall submit this plan to the Administrator for approval within 360 days of the initial startup of the affected facility or by November 30, 2009, whichever date comes later. If the plan is approved, the owner or operator shall maintain records of predicted nitrogen oxide emission rates and the monitored operating conditions, including steam generating unit load, identified in the plan. The plan shall:

(1) Identify the specific operating conditions to be monitored and the relationship between these operating conditions and NO_X emission rates (*i.e.*, ng/J or lbs/MMBtu heat input). Steam generating unit operating conditions include, but are not limited to, the degree of staged combustion (*i.e.*, the ratio of primary air to secondary and/or tertiary air) and the level of excess air (*i.e.*, flue gas O_2 level);

(2) Include the data and information that the owner or operator used to identify the relationship between NO_X emission rates and these operating conditions; and

(3) Identify how these operating conditions, including steam generating unit load, will be monitored under §60.48b(g) on an hourly basis by the owner or operator during the period of operation of the affected facility; the quality assurance procedures or practices that will be employed to ensure that the data generated by monitoring these operating conditions will be representative and accurate; and the type and format of the records of these operating conditions, including steam generating unit load, that will be maintained by the owner or operator under §60.49b(g).

(d) Except as provided in paragraph (d)(2) of this section, the owner or operator of an affected facility shall record and maintain records as specified in paragraph (d)(1) of this section.

(1) The owner or operator of an affected facility shall record and maintain records of the amounts of each fuel combusted during each day and calculate the annual capacity factor individually for coal, distillate oil, residual oil, natural gas, wood, and municipal-type solid waste for the reporting period. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month.

(2) As an alternative to meeting the requirements of paragraph (d)(1) of this section, the owner or operator of an affected facility that is subject to a federally enforceable permit restricting fuel use to a single fuel such that the facility is not required to continuously monitor any emissions (excluding opacity) or parameters indicative of emissions may elect to record and maintain records of the amount of each fuel combusted during each calendar month.

(e) For an affected facility that combusts residual oil and meets the criteria under §60.46b(e)(4), §60.44b(j), or (k), the owner or operator shall maintain records of the nitrogen content of the residual oil combusted in the affected facility and calculate the average fuel nitrogen content for the reporting period. The nitrogen content shall be determined using ASTM Method D4629 (incorporated by reference, see §60.17), or fuel suppliers. If residual oil blends are being combusted, fuel nitrogen specifications may be prorated based on the ratio of residual oils of different nitrogen content in the fuel blend.

(f) For an affected facility subject to the opacity standard in §60.43b, the owner or operator shall maintain records of opacity. In addition, an owner or operator that elects to monitor emissions according to the requirements in §60.48b(a) shall maintain records according to the requirements specified in paragraphs (f)(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 (f)(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 (f)(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.

(g) Except as provided under paragraph (p) of this section, the owner or operator of an affected facility subject to the NO_X standards under §60.44b shall maintain records of the following information for each steam generating unit operating day:

(1) Calendar date;

(2) The average hourly NO_X emission rates (expressed as NO_2) (ng/J or lb/MMBtu heat input) measured or predicted;

(3) The 30-day average NO_X emission rates (ng/J or lb/MMBtu heat input) calculated at the end of each steam generating unit operating day from the measured or predicted hourly nitrogen oxide emission rates for the preceding 30 steam generating unit operating days;

(4) Identification of the steam generating unit operating days when the calculated 30-day average NO_X emission rates are in excess of the NO_X emissions standards under §60.44b, with the reasons for such excess emissions as well as a description of corrective actions taken;

(5) Identification of the steam generating unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken;

(6) Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data;

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

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

(9) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3; and

(10) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part.

(h) The owner or operator of any affected facility in any category listed in paragraphs (h)(1) or (2) of this section is required to submit excess emission reports for any excess emissions that occurred during the reporting period.

(1) Any affected facility subject to the opacity standards in §60.43b(f) or to the operating parameter monitoring requirements in §60.13(i)(1).

(2) Any affected facility that is subject to the NO_X standard of §60.44b, and that:

(i) Combusts natural gas, distillate oil, gasified coal, or residual oil with a nitrogen content of 0.3 weight percent or less; or

(ii) Has a heat input capacity of 73 MW (250 MMBtu/hr) or less and is required to monitor NO_X emissions on a continuous basis under §60.48b(g)(1) or steam generating unit operating conditions under §60.48b(g)(2).

(3) For the purpose of §60.43b, excess emissions are defined as all 6-minute periods during which the average opacity exceeds the opacity standards under §60.43b(f).

(4) For purposes of §60.48b(g)(1), excess emissions are defined as any calculated 30-day rolling average NO_X emission rate, as determined under §60.46b(e), that exceeds the applicable emission limits in §60.44b.

(i) The owner or operator of any affected facility subject to the continuous monitoring requirements for NO_X under §60.48(b) shall submit reports containing the information recorded under paragraph (g) of this section.

(j) The owner or operator of any affected facility subject to the SO_2 standards under §60.42b shall submit reports.

(k) For each affected facility subject to the compliance and performance testing requirements of §60.45b and the reporting requirement in paragraph (j) of this section, the following information shall be reported to the Administrator:

(1) Calendar dates covered in the reporting period;

(2) Each 30-day average SO_2 emission rate (ng/J or lb/MMBtu heat input) measured during the reporting period, ending with the last 30-day period; reasons for noncompliance with the emission standards; and a description of corrective actions taken; For an exceedance due to maintenance of the SO_2 control system covered in paragraph 60.45b(a), the report shall identify the days on which the maintenance was performed and a description of the maintenance;

(3) Each 30-day average percent reduction in SO_2 emissions calculated during the reporting period, ending with the last 30-day period; reasons for noncompliance with the emission standards; and a description of corrective actions taken;

(4) Identification of the steam generating unit operating days that coal or oil was combusted and for which SO_2 or diluent (O_2 or CO_2) data have not been obtained by an approved method for at least 75 percent of the operating hours in the steam generating unit operating day; justification for not obtaining sufficient data; and description of corrective action taken;

(5) Identification of the times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and description of corrective action taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit;

(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 the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3;

(10) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part; and

(11) The annual capacity factor of each fired as provided under paragraph (d) of this section.

(l) For each affected facility subject to the compliance and performance testing requirements of §60.45b(d) and the reporting requirements of paragraph (j) of this section, the following information shall be reported to the Administrator:

(1) Calendar dates when the facility was in operation during the reporting period;

(2) The 24-hour average SO_2 emission rate measured for each steam generating unit operating day during the reporting period that coal or oil was combusted, ending in the last 24-hour period in the quarter; reasons for noncompliance with the emission standards; and a description of corrective actions taken;

(3) Identification of the steam generating unit operating days that coal or oil was combusted for which $S0_2$ or diluent (O_2 or CO_2) data have not been obtained by an approved method for at least 75 percent of the operating hours; justification for not obtaining sufficient data; and description of corrective action taken;

(4) Identification of the times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and description of corrective action taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit;

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

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

(7) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(8) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3; and

(9) Results of daily CEMS drift tests and quarterly accuracy assessments as required under Procedure 1 of appendix F 1 of this part. If the owner or operator elects to implement the alternative data assessment procedures described in §§60.47b(e)(4)(i) through (e)(4)(iii), 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 §§60.47b(e)(4)(i) through (e)(4)(iii).

(m) For each affected facility subject to the SO_2 standards in §60.42(b) for which the minimum amount of data required in §60.47b(c) were not obtained during the reporting period, the following information is reported to the Administrator in addition to that required under paragraph (k) of this section:

(1) The number of hourly averages available for outlet emission rates and inlet emission rates;

(2) The standard deviation of hourly averages for outlet emission rates and inlet emission rates, as determined in Method 19 of appendix A of this part, section 7;

(3) The lower confidence limit for the mean outlet emission rate and the upper confidence limit for the mean inlet emission rate, as calculated in Method 19 of appendix A of this part, section 7; and

(4) The ratio of the lower confidence limit for the mean outlet emission rate and the allowable emission rate, as determined in Method 19 of appendix A of this part, section 7.

(n) If a percent removal efficiency by fuel pretreatment (*i.e.*, $\%R_f$) is used to determine the overall percent reduction (*i.e.*, $\%R_o$) under §60.45b, the owner or operator of the affected facility shall submit a signed statement with the report.

(1) Indicating what removal efficiency by fuel pretreatment (*i.e.*, $\%R_f$) was credited during the reporting period;

(2) Listing the quantity, heat content, and date each pre-treated fuel shipment was received during the reporting period, 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 reporting period;

(3) Documenting the transport of the fuel from the fuel pretreatment facility to the steam generating unit; and

(4) Including a signed statement from the owner or operator of the fuel pretreatment facility certifying that the percent removal efficiency achieved by fuel pretreatment was determined in accordance with the provisions of Method 19 of appendix A of this part and listing the heat content and sulfur content of each fuel before and after fuel pretreatment.

(o) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of 2 years following the date of such record.

(p) The owner or operator of an affected facility described in §60.44b(j) or (k) shall maintain records of the following information for each steam generating unit operating day:

(1) Calendar date;

(2) The number of hours of operation; and

(3) A record of the hourly steam load.

(q) The owner or operator of an affected facility described in §60.44b(j) or §60.44b(k) shall submit to the Administrator a report containing:

(1) The annual capacity factor over the previous 12 months;

(2) The average fuel nitrogen content during the reporting period, if residual oil was fired; and

(3) If the affected facility meets the criteria described in §60.44b(j), the results of any NO_X emission tests required during the reporting period, the hours of operation during the reporting period, and the hours of operation since the last NO_X emission test.

(r) The owner or operator of an affected facility who elects to use the fuel based compliance alternatives in §60.42b or §60.43b shall either:

(1) The owner or operator of an affected facility who elects to demonstrate that the affected facility combusts only very low sulfur oil, natural gas, wood, a mixture of these fuels, or any of these fuels (or a mixture of these fuels) in combination with other fuels that are known to contain an insignificant amount of sulfur in §60.42b(j) or §60.42b(k) shall obtain and maintain at the affected facility fuel receipts (such as a current, valid purchase contract, tariff sheet, or transportation contract) from the fuel supplier that certify that the oil meets the definition of distillate oil and gaseous fuel meets the definition of natural gas as defined in §60.41b and the applicable sulfur limit. For the purposes of this section, the distillate oil need not meet the fuel nitrogen content specification in the definition of distillate oil. Reports shall be submitted to the Administrator certifying that only very low sulfur oil meeting this definition, natural gas, wood, and/or other fuels that are known to contain insignificant amounts of sulfur were combusted in the affected facility during the reporting period; or

(2) The owner or operator of an affected facility who elects to demonstrate compliance based on fuel analysis in §60.42b or §60.43b shall develop and submit a site-specific fuel analysis plan to the Administrator for review and approval no later than 60 days before the date you intend to demonstrate compliance. Each fuel analysis plan shall include a minimum initial requirement of weekly testing and each analysis report shall contain, at a minimum, the following information:

(i) The potential sulfur emissions rate of the representative fuel mixture in ng/J heat input;

(ii) The method used to determine the potential sulfur emissions rate of each constituent of the mixture. For distillate oil and natural gas a fuel receipt or tariff sheet is acceptable;

(iii) The ratio of different fuels in the mixture; and

(iv) The owner or operator can petition the Administrator to approve monthly or quarterly sampling in place of weekly sampling.

(s) Facility specific NO_X standard for Cytec Industries Fortier Plant's C.AOG incinerator located in Westwego, Louisiana:

(1) *Definitions.*

Oxidation zone is defined as the portion of the C.AOG incinerator that extends from the inlet of the oxidizing zone combustion air to the outlet gas stack.

Reducing zone is defined as the portion of the C.AOG incinerator that extends from the burner section to the inlet of the oxidizing zone combustion air.

Total inlet air is defined as the total amount of air introduced into the C.AOG incinerator for combustion of natural gas and chemical by-product waste and is equal to the sum of the air flow into the reducing zone and the air flow into the oxidation zone.

(2) *Standard for nitrogen oxides.* (i) When fossil fuel alone is combusted, the NO_X emission limit for fossil fuel in §60.44b(a) applies.

(ii) When natural gas and chemical by-product waste are simultaneously combusted, the NO_X emission limit is 289 ng/J (0.67 lb/MMBtu) and a maximum of 81 percent of the total inlet air provided for combustion shall be provided to the reducing zone of the C.AOG incinerator.

(3) *Emission monitoring.* (i) The percent of total inlet air provided to the reducing zone shall be determined at least every 15 minutes by measuring the air flow of all the air entering the reducing zone and the air flow of all the air entering the oxidation zone, and compliance with the percentage of total inlet air that is provided to the reducing zone shall be determined on a 3-hour average basis.

(ii) The NO_X emission limit shall be determined by the compliance and performance test methods and procedures for NO_X in §60.46b(i).

(iii) The monitoring of the NO_X emission limit shall be performed in accordance with §60.48b.

(4) *Reporting and recordkeeping requirements.* (i) The owner or operator of the C.AOG incinerator shall submit a report on any excursions from the limits required by paragraph (a)(2) of this section to the Administrator with the quarterly report required by paragraph (i) of this section.

(ii) The owner or operator of the C.AOG incinerator shall keep records of the monitoring required by paragraph (a)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner of operator of the C.AOG incinerator shall perform all the applicable reporting and recordkeeping requirements of this section.

(t) Facility-specific NO_X standard for Rohm and Haas Kentucky Incorporated's Boiler No. 100 located in Louisville, Kentucky:

(1) *Definitions.*

Air ratio control damper is defined as the part of the low NO_X burner that is adjusted to control the split of total combustion air delivered to the reducing and oxidation portions of the combustion flame.

Flue gas recirculation line is defined as the part of Boiler No. 100 that recirculates a portion of the boiler flue gas back into the combustion air.

(2) *Standard for nitrogen oxides.* (i) When fossil fuel alone is combusted, the NO_X emission limit for fossil fuel in §60.44b(a) applies.

(ii) When fossil fuel and chemical by-product waste are simultaneously combusted, the NO_X emission limit is 473 ng/J (1.1 lb/MMBtu), and the air ratio control damper tee handle shall be at a minimum of 5 inches (12.7 centimeters) out of the boiler, and the flue gas recirculation line shall be operated at a minimum of 10 percent open as indicated by its valve opening position indicator.

(3) *Emission monitoring for nitrogen oxides.* (i) The air ratio control damper tee handle setting and the flue gas recirculation line valve opening position indicator setting shall be recorded during each 8-hour operating shift.

(ii) The NO_X emission limit shall be determined by the compliance and performance test methods and procedures for NO_X in §60.46b.

(iii) The monitoring of the NO_X emission limit shall be performed in accordance with §60.48b.

(4) *Reporting and recordkeeping requirements.* (i) The owner or operator of Boiler No. 100 shall submit a report on any excursions from the limits required by paragraph (b)(2) of this section to the Administrator with the quarterly report required by §60.49b(i).

(ii) The owner or operator of Boiler No. 100 shall keep records of the monitoring required by paragraph (b)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner of operator of Boiler No. 100 shall perform all the applicable reporting and recordkeeping requirements of §60.49b.

(u) *Site-specific standard for Merck & Co., Inc.'s Stonewall Plant in Elkton, Virginia.* (1) This paragraph (u) applies only to the pharmaceutical manufacturing facility, commonly referred to as the Stonewall Plant, located at Route 340 South, in Elkton, Virginia ("site") and only to the natural gas-fired boilers installed as part of the powerhouse conversion required pursuant to 40 CFR 52.2454(g). The requirements of this paragraph shall apply, and the requirements of §§60.40b through 60.49b(t) shall not apply, to the natural gas-fired boilers installed pursuant to 40 CFR 52.2454(g).

(i) The site shall equip the natural gas-fired boilers with low NO_X technology.

(ii) The site shall install, calibrate, maintain, and operate a continuous monitoring and recording system for measuring NO_X emissions discharged to the atmosphere and opacity using a continuous emissions monitoring system or a predictive emissions monitoring system.

(iii) Within 180 days of the completion of the powerhouse conversion, as required by 40 CFR 52.2454, the site shall perform a performance test to quantify criteria pollutant emissions.

(2) [Reserved]

(v) The owner or operator of an affected facility may submit electronic quarterly reports for SO_2 and/or NO_X and/or opacity in lieu of submitting the written reports required under paragraphs (h), (i), (j), (k) or (l) 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.

(w) The reporting period for the reports required under this subpart is each 6 month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

(x) Facility-specific NO_X standard for Weyerhaeuser Company's No. 2 Power Boiler located in New Bern, North Carolina:

(1) *Standard for nitrogen oxides.* (i) When fossil fuel alone is combusted, the NO_X emission limit for fossil fuel in §60.44b(a) applies.

(ii) When fossil fuel and chemical by-product waste are simultaneously combusted, the NO_X emission limit is 215 ng/J (0.5 lb/MMBtu).

(2) *Emission monitoring for nitrogen oxides.* (i) The NO_X emissions shall be determined by the compliance and performance test methods and procedures for NO_X in §60.46b.

(ii) The monitoring of the NO_X emissions shall be performed in accordance with §60.48b.

(3) *Reporting and recordkeeping requirements.* (i) The owner or operator of the No. 2 Power Boiler shall submit a report on any excursions from the limits required by paragraph (x)(2) of this section to the Administrator with the quarterly report required by §60.49b(i).

(ii) The owner or operator of the No. 2 Power Boiler shall keep records of the monitoring required by paragraph (x)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner or operator of the No. 2 Power Boiler shall perform all the applicable reporting and recordkeeping requirements of §60.49b.

(y) Facility-specific NO_X standard for INEOS USA's AOGI located in Lima, Ohio:

(1) *Standard for NO_X.* (i) When fossil fuel alone is combusted, the NO_X emission limit for fossil fuel in §60.44b(a) applies.

(ii) When fossil fuel and chemical byproduct/waste are simultaneously combusted, the NO_X emission limit is 645 ng/J (1.5 lb/MMBtu).

(2) *Emission monitoring for NO_X.* (i) The NO_X emissions shall be determined by the compliance and performance test methods and procedures for NO_X in §60.46b.

(ii) The monitoring of the NO_X emissions shall be performed in accordance with §60.48b.

(3) *Reporting and recordkeeping requirements.* (i) The owner or operator of the AOGI shall submit a report on any excursions from the limits required by paragraph (y)(2) of this section to the Administrator with the quarterly report required by paragraph (i) of this section.

(ii) The owner or operator of the AOGI shall keep records of the monitoring required by paragraph (y)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner or operator of the AOGI shall perform all the applicable reporting and recordkeeping requirements of this section.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5089, Jan. 28, 2009; 77 FR 9461, Feb. 16, 2012]

Title 40: Protection of Environment
PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES (CONTINUED)
Subpart KKKK—Standards of Performance for Stationary Combustion Turbines

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§60.4400 How do I conduct the initial and subsequent performance tests, regarding NO_X?

(a) You must conduct an initial performance test, as required in §60.8. Subsequent NO_X performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test).

(1) There are two general methodologies that you may use to conduct the performance tests. For each test run:

(i) Measure the NO_X concentration (in parts per million (ppm)), using EPA Method 7E or EPA Method 20 in appendix A of this part. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A of this part, and measure and record the electrical and thermal output from the unit. Then, use the following equation to calculate the NO_X emission rate:

$$E = \frac{1.194 \times 10^{-7} * (NO_X)_c * Q_{std}}{P} \quad (Eq. 5)$$

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Where:

E = NO_X emission rate, in lb/MWh

1.194×10^{-7} = conversion constant, in lb/dscf-ppm

$(NO_X)_c$ = average NO_X concentration for the run, in ppm

Q_{std} = stack gas volumetric flow rate, in dscf/hr

P = gross electrical and mechanical energy output of the combustion turbine, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for combined heat and power operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation, in MW, calculated according to §60.4350(f)(2); or

(ii) Measure the NO_X and diluent gas concentrations, using either EPA Methods 7E and 3A, or EPA Method 20 in appendix A of this part. Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A of this part to calculate the NO_X emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in §60.4350(f) to calculate the NO_X emission rate in lb/MWh.

(2) Sampling traverse points for NO_X and (if applicable) diluent gas are to be selected following EPA Method 20 or EPA Method 1 (non-particulate procedures), and sampled for equal time intervals. The sampling must be performed with a traversing single-hole probe, or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

(3) Notwithstanding paragraph (a)(2) of this section, you may test at fewer points than are specified in EPA Method 1 or EPA Method 20 in appendix A of this part if the following conditions are met:

(i) You may perform a stratification test for NO_X and diluent pursuant to

(A) [Reserved], or

(B) The procedures specified in section 6.5.6.1(a) through (e) of appendix A of part 75 of this chapter.

(ii) Once the stratification sampling is completed, you may use the following alternative sample point selection criteria for the performance test:

(A) If each of the individual traverse point NO_X concentrations is within ±10 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±5ppm or ±0.5 percent CO_2 (or O_2) from the mean for all traverse points, then you may use three points (located either 16.7, 50.0 and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall). The three points must be located along the measurement line that exhibited the highest average NO_X concentration during the stratification test; or

(B) For turbines with a NO_X standard greater than 15 ppm @ 15% O_2, you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO_X concentrations is within ±5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±3ppm or ±0.3 percent CO_2 (or O_2) from the mean for all traverse points; or

(C) For turbines with a NO_X standard less than or equal to 15 ppm @ 15% O_2, you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO_X concentrations is within ±2.5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±1ppm or ±0.15 percent CO_2 (or O_2) from the mean for all traverse points.

(b) The performance test must be done at any load condition within plus or minus 25 percent of 100 percent of peak load. You may perform testing at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice. You must conduct three separate test runs for each performance test. The minimum time per run is 20 minutes.

(1) If the stationary combustion turbine combusts both oil and gas as primary or backup fuels, separate performance testing is required for each fuel.

(2) For a combined cycle and CHP turbine systems with supplemental heat (duct burner), you must measure the total NO_X emissions after the duct burner rather than directly after the turbine. The duct burner must be in operation during the performance test.

(3) If water or steam injection is used to control NO_X with no additional post-combustion NO_X control and you choose to monitor the steam or water to fuel ratio in accordance with §60.4335, then that monitoring system must be operated concurrently with each EPA Method 20 or EPA Method 7E run and must be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable §60.4320 NO_X emission limit.

(4) Compliance with the applicable emission limit in §60.4320 must be demonstrated at each tested load level. Compliance is achieved if the three-run arithmetic average NO_X emission rate at each tested level meets the applicable emission limit in §60.4320.

(5) If you elect to install a CEMS, the performance evaluation of the CEMS may either be conducted separately or (as described in §60.4405) as part of the initial performance test of the affected unit.

(6) The ambient temperature must be greater than 0 °F during the performance test.

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Subpart KKKK—Standards of Performance for Stationary Combustion Turbines

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§60.4345 What are the requirements for the continuous emission monitoring system equipment, if I choose to use this option?

If the option to use a NO_X CEMS is chosen:

(a) Each NO_X diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in appendix B to this part, except the 7-day calibration drift is based on unit operating days, not calendar days. With state approval, Procedure 1 in appendix F to this part is not required. Alternatively, a NO_X diluent CEMS that is installed and certified according to appendix A of part 75 of this chapter is acceptable for use under this subpart. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis.

(b) As specified in §60.13(e)(2), during each full unit operating hour, both the NO_X monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required for each monitor to validate the NO_X emission rate for the hour.

(c) Each fuel flowmeter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, with state approval, fuel flowmeters that meet the installation, certification, and quality assurance requirements of appendix D to part 75 of this chapter are acceptable for use under this subpart.

(d) Each watt meter, steam flow meter, and each pressure or temperature measurement device shall be installed, calibrated, maintained, and operated according to manufacturer's instructions.

(e) The owner or operator shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in paragraphs (a), (c), and (d) of this section. For the CEMS and fuel flow meters, the owner or operator may, with state approval, satisfy the requirements of this paragraph by implementing the QA program and plan described in section 1 of appendix B to part 75 of this chapter.

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Title 40: Protection of Environment
PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES (CONTINUED)
Subpart KKKK—Standards of Performance for Stationary Combustion Turbines

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§60.4350 How do I use data from the continuous emission monitoring equipment to identify excess emissions?

For purposes of identifying excess emissions:

(a) All CEMS data must be reduced to hourly averages as specified in §60.13(h).

(b) For each unit operating hour in which a valid hourly average, as described in §60.4345(b), is obtained for both NO_X and diluent monitors, the data acquisition and handling system must calculate and record the hourly NO_X emission rate in units of ppm or lb/MMBtu, using the appropriate equation from method 19 in appendix A of this part. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2 (or the hourly average CO_2 concentration is less than 1.0 percent CO_2), a diluent cap value of 19.0 percent O_2 or 1.0 percent CO_2 (as applicable) may be used in the emission calculations.

(c) Correction of measured NO_X concentrations to 15 percent O_2 is not allowed.

(d) If you have installed and certified a NO_X diluent CEMS to meet the requirements of part 75 of this chapter, states can approve that only quality assured data from the CEMS shall be used to identify excess emissions under this subpart. Periods where the missing data substitution procedures in subpart D of part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under §60.7(c).

(e) All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.

(f) Calculate the hourly average NO_X emission rates, in units of the emission standards under §60.4320, using either ppm for units complying with the concentration limit or the following equation for units complying with the output based standard:

(1) For simple-cycle operation:

$$E = \frac{(NO_x)_h * (HI)_h}{P} \qquad \text{(Eq. 1)}$$

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Where:

E = hourly NO_X emission rate, in lb/MWh,

$(NO_X)_h$ = hourly NO_X emission rate, in lb/MMBtu,

$(HI)_h$ = hourly heat input rate to the unit, in MMBtu/h, measured using the fuel flowmeter(s), *e.g.*, calculated using Equation D-15a in appendix D to part 75 of this chapter, and

P = gross energy output of the combustion turbine in MW.

(2) For combined-cycle and combined heat and power complying with the output-based standard, use Equation 1 of this subpart, except that the gross energy output is calculated as the sum of the total electrical and mechanical energy generated by the combustion turbine, the additional electrical or mechanical energy (if any) generated by the steam turbine following the heat recovery steam generator, and 100 percent of the total useful thermal energy output that is not used to generate additional electricity or mechanical output, expressed in equivalent MW, as in the following equations:

$$P = (Pe)_t + (Pe)_c + Ps + Po \qquad \text{(Eq. 2)}$$

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Where:

P = gross energy output of the stationary combustion turbine system in MW.

$(Pe)_t$ = electrical or mechanical energy output of the combustion turbine in MW,

$(Pe)_c$ = electrical or mechanical energy output (if any) of the steam turbine in MW, and

$$Ps = \frac{Q * H}{3.413 \times 10^6 \text{ Btu/MWh}} \quad \text{(Eq. 3)}$$

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Where:

Ps = useful thermal energy of the steam, measured relative to ISO conditions, not used to generate additional electric or mechanical output, in MW,

Q = measured steam flow rate in lb/h,

H = enthalpy of the steam at measured temperature and pressure relative to ISO conditions, in Btu/lb, and $3.413 \times 10_6$ = conversion from Btu/h to MW.

Po = other useful heat recovery, measured relative to ISO conditions, not used for steam generation or performance enhancement of the combustion turbine.

(3) For mechanical drive applications complying with the output-based standard, use the following equation:

$$E = \frac{(NO_x)_m}{BL * AL} \quad \text{(Eq. 4)}$$

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Where:

E = NO_X emission rate in lb/MWh,

$(NO_X)_m$ = NO_X emission rate in lb/h,

BL = manufacturer's base load rating of turbine, in MW, and

AL = actual load as a percentage of the base load.

(g) For simple cycle units without heat recovery, use the calculated hourly average emission rates from paragraph (f) of this section to assess excess emissions on a 4-hour rolling average basis, as described in §60.4380(b)(1).

(h) For combined cycle and combined heat and power units with heat recovery, use the calculated hourly average emission rates from paragraph (f) of this section to assess excess emissions on a 30 unit operating day rolling average basis, as described in §60.4380(b)(1).

Need assistance?