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%CO₂=carbon dioxide concentration, percent dry basis.

F_c=factor as determined in appropriate sections of Method 19.

(ii) If and only if the average F_c factor in Method 19 is used to calculate E and either E is from 0.97 to 1.00 of the emission standard or the relative accuracy of a continuous emission monitoring system is from 17 to 20 percent, then three runs of Method 3B shall be used to determine the O₂ and CO₂ concentration according to the procedures in paragraph (b) (2)(ii), (4)(ii), or (5)(ii) of this section. Then if F_o (average of three runs), as calculated from the equation in Method 3B, is more than ±3 percent than the average F_o value, as determined from the average values of F_d and F_c in Method 19, i.e., F_{oa}=0.209 (F_{da}/F_{ca}), then the following procedure shall be followed:

(A) When F_o is less than 0.97 F_{oa}, then E shall be increased by that proportion under 0.97 F_{oa}, e.g., if F_o is 0.95 F_{oa}, E shall be increased by 2 percent. This recalculated value shall be used to determine compliance with the emission standard.

(B) When F_o is less than 0.97 F_{oa} and when the average difference (d) between the continuous monitor minus the reference methods is negative, then E shall be increased by that proportion under 0.97 F_{oa}, e.g., if F_o is 0.95 F_{oa}, E shall be increased by 2 percent. This recalculated value shall be used to determine compliance with the relative accuracy specification.

(C) When F_o is greater than 1.03 F_{oa} and when the average difference d is positive, then E shall be decreased by that proportion over 1.03 F_{oa}, e.g., if F_o is 1.05 F_{oa}, E shall be decreased by 2 percent. This recalculated value shall be used to determine compliance with the relative accuracy specification.

(2) For Method 5 or 5B, Method 17 may be used at facilities with or without wet FGD systems if the stack gas temperature at the sampling location does not exceed an average temperature of 160 °C (320 °F). The procedures of sections 2.1 and 2.3 of Method 5B may be used with Method 17 only if it is used after wet FGD systems. Method 17 shall not be used after wet FGD systems if the effluent gas is saturated or laden with water droplets.

(3) Particulate matter and SO₂ may be determined simultaneously with the Method 5 train provided that the following changes are made:

(i) The filter and impinger apparatus in sections 2.1.5 and 2.1.6 of Method 8 is used in place of the condenser (section 2.1.7) of Method 5.

(ii) All applicable procedures in Method 8 for the determination of SO₂ (including moisture) are used:

(4) For Method 6, Method 6C may be used. Method 6A may also be used whenever Methods 6 and 3B data are specified to determine the SO₂ emission rate, under the conditions in paragraph (d)(1) of this section.

(5) For Method 7, Method 7A, 7C, 7D, or 7E may be used. If Method 7C, 7D, or 7E is used, the sampling time for each run shall be at least 1 hour and the integrated sampling approach shall be used to determine the O₂ concentration (%O₂) for the emission rate correction factor.

(6) For Method 3, Method 3A or 3B may be used.

(7) For Method 3B, Method 3A may be used.

[54 FR 6662, Feb. 14, 1989; 54 FR 21344, May 17, 1989, as amended at 55 FR 5212, Feb. 14, 1990]

Subpart Da—Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978

SOURCE: 44 FR 33613, June 11, 1979, unless otherwise noted.

§ 60.40a Applicability and designation of affected facility.

(a) The affected facility to which this subpart applies is each electric utility steam generating unit:

(1) That is capable of combusting more than 73 megawatts (250 million Btu/hour) heat input of fossil fuel (either alone or in combination with any other fuel); and

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

(b) This subpart applies to electric utility combined cycle gas turbines that are capable of combusting more

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than 73 megawatts (250 million Btu/hour) heat input of fossil fuel in the steam generator. Only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The gas turbine emissions are subject to subpart GG.)

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

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

§ 60.41a Definitions.

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

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

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

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

Subbituminous coal means coal that is classified as subbituminous A, B, or C according to the American Society of Testing and Materials (ASTM) Standard Specification for Classification of Coals by Rank D388-77 (incorporated by reference—see § 60.17).

Lignite means coal that is classified as lignite A or B according to the American Society of Testing and Materials' (ASTM) Standard Specification for Classification of Coals by Rank D388-77 (incorporated by reference—see § 60.17).

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

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

(a) For particulate matter is:

(1) 3,000 ng/J (7.0 lb/million Btu) heat input for solid fuel; and

(2) 75 ng/J (0.17 lb/million Btu) heat input for liquid fuels.

(b) For sulfur dioxide is determined under § 60.48a(b).

(c) For nitrogen oxides is:

(1) 290 ng/J (0.67 lb/million Btu) heat input for gaseous fuels;

(2) 310 ng/J (0.72 lb/million Btu) heat input for liquid fuels; and

(3) 990 ng/J (2.30 lb/million Btu) heat input for solid fuels.

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

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

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

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

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

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

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

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

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

Spinning reserve means the sum of the unutilized net generating capability of all units of the electric utility company that are synchronized to the

power distribution system and that are capable of immediately accepting additional load. The electric generating capability of equipment under multiple ownership is prorated based on ownership unless the proportional entitlement to electric output is otherwise established by contractual arrangement.

Available purchase power means the lesser of the following:

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

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

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

Emergency condition means that period of time when:

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

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

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

- (b) The electric generation demand is being shifted as quickly as possible from an affected facility with a malfunctioning flue gas desulfurization

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system to one or more electrical generating units held in reserve by the principal company or by a neighboring company, or

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

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

Potential electrical output capacity is defined as 33 percent of the maximum design heat input capacity of the steam generating unit (e.g., a steam generating unit with a 100-MW (340 million Btu/hr) fossil-fuel heat input capacity would have a 33-MW potential electrical output capacity). For electric utility combined cycle gas turbines the potential electrical output capacity is determined on the basis of the fossil-fuel firing capacity of the steam generator exclusive of the heat input and electrical power contribution by the gas turbine.

Anthracite means coal that is classified as anthracite according to the American Society of Testing and Materials' (ASTM) Standard Specification for Classification of Coals by Rank D388-77 (incorporated by reference—see §60.17).

Solid-derived fuel means any solid, liquid, or gaseous fuel derived from solid fuel for the purpose of creating useful heat and includes, but is not limited

to, solvent refined coal, liquified coal, and gasified coal.

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

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

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

Boiler operating day means a 24-hour period during which fossil fuel is combusted in a steam generating unit for the entire 24 hours.

[44 FR 33613, June 11, 1979, as amended at 48 FR 3737, Jan. 27, 1983]

§ 60.42a Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted under §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain particulate matter in excess of:

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

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

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

(b) On and after the date the particulate matter performance test required to be conducted under §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

§ 60.43a Standard for sulfur dioxide.

(a) On and after the date on which the initial performance test required to be conducted under §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere

from any affected facility which combusts solid fuel or solid-derived fuel, except as provided under paragraphs (c), (d), (f) or (h) of this section, any gases which contain sulfur dioxide in excess of:

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

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

(b) On and after the date on which the initial performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts liquid or gaseous fuels (except for liquid or gaseous fuels derived from solid fuels and as provided under paragraphs (e) or (h) of this section), any gases which contain sulfur dioxide in excess of:

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

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

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

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

(1) Combusts 100 percent anthracite,

(2) Is classified as a resource recovery facility, or

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

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

(f) The emission reduction requirements under this section do not apply to any affected facility that is operated under an SO₂ commercial demonstration permit issued by the Administrator in accordance with the provisions of § 60.45a.

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

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

(1) If emissions of sulfur dioxide to the atmosphere are greater than 260 ng/J (0.60 lb/million Btu) heat input

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

(2) If emissions of sulfur dioxide to the atmosphere are equal to or less than 260 ng/J (0.60 lb/million Btu) heat input:

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

where:

E_s is the prorated sulfur dioxide emission limit (ng/J heat input),

$\%P_s$ is the percentage of potential sulfur dioxide emission allowed.

x is the percentage of total heat input derived from the combustion of liquid or gaseous fuels (excluding solid-derived fuels)

y is the percentage of total heat input derived from the combustion of solid fuel (including solid-derived fuels)

[44 FR 33613, June 11, 1979, as amended at 54 FR 6663, Feb. 14, 1989; 54 FR 21344, May 17, 1989]

§ 60.44a Standard for nitrogen oxides.

(a) On and after the date on which the initial performance test required to

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be conducted under §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility, except as provided under paragraph (b) of this section, any gases which contain nitrogen oxides in excess of the following emission limits, based on a 30-day rolling average.

(1) NO_x emission limits.

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

¹Exempt from NO_x standards and NO_x monitoring requirements.

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

(2) NO_x reduction requirement.

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

(b) The emission limitations under paragraph (a) of this section do not apply to any affected facility which is combusting coal-derived liquid fuel and is operating under a commercial demonstration permit issued by the Administrator in accordance with the provisions of §60.45a.

(c) When two or more fuels are combusted simultaneously, the applicable

standard is determined by proration using the following formula:

$$E_n = [86w + 130x + 210y + 260z + 340v] / 100$$

where:

E_n is the applicable standard for nitrogen oxides when multiple fuels are combusted simultaneously (ng/J heat input);

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

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

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

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

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

[44 FR 33613, June 11, 1979, as amended at 54 FR 6664, Feb. 14, 1989]

§ 60.45a Commercial demonstration permit.

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

(b) An owner or operator of an affected facility that combusts solid solvent refined coal (SRC-I) and who is issued a commercial demonstration permit by the Administrator is not subject to the SO_2 emission reduction requirements under §60.43a(c) but must, as a minimum, reduce SO_2 emissions to 20 percent of the potential combustion concentration (80 percent reduction) for each 24-hour period of steam generator operation and to less than 520 ng/J (1.20 lb/million Btu) heat input on a 30-day rolling average basis.

(c) An owner or operator of a fluidized bed combustion electric utility steam generator (atmospheric or pressurized) who is issued a commercial

demonstration permit by the Administrator is not subject to the SO₂ emission reduction requirements under § 60.43a(a) but must, as a minimum, reduce SO₂ emissions to 15 percent of the potential combustion concentration (85 percent reduction) on a 30-day rolling average basis and to less than 520 ng/J (1.20 lb/million Btu) heat input on a 30-day rolling average basis.

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

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

Technology	Pollutant	Equivalent electrical capacity (MW electrical output)
Solid solvent refined coal (SRC)	SO ₂	6,000–10,000
Fluidized bed combustion (atmospheric)		
Fluidized bed combustion (pressurized)	SO ₂	400–3,000
Coal liquefaction	NO _x	400–1,200 750–10,000
Total allowable for all technologies		15,000

§ 60.46a Compliance provisions.

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

(b) Compliance with the nitrogen oxides emission limitation under § 60.44a(a) constitutes compliance with the percent reduction requirements under § 60.44a(a)(2).

(c) The particulate matter emission standards under § 60.42a and the nitrogen oxides emission standards under § 60.44a apply at all times except during

periods of startup, shutdown, or malfunction. The sulfur dioxide emission standards under § 60.43a apply at all times except during periods of startup, shutdown, or when both emergency conditions exist and the procedures under paragraph (d) of this section are implemented.

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

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

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

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

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

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

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

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

(e) After the initial performance test required under § 60.8, compliance with

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the sulfur dioxide emission limitations and percentage reduction requirements under § 60.43a and the nitrogen oxides emission limitations under § 60.44a is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30 day average emission rate for both sulfur dioxide and nitrogen oxides and a new percent reduction for sulfur dioxide are calculated to show compliance with the standards.

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

(g) Compliance is determined by calculating the arithmetic average of all hourly emission rates for SO₂ and NO_x for the 30 successive boiler operating days, except for data obtained during startup, shutdown, malfunction (NO_x only), or emergency conditions (SO₂ only). Compliance with the percentage reduction requirement for SO₂ is determined based on the average inlet and average outlet SO₂ emission rates for the 30 successive boiler operating days.

(h) If an owner or operator has not obtained the minimum quantity of emission data as required under § 60.47a of this subpart, compliance of the affected facility with the emission requirements under §§ 60.43a and 60.44a of this subpart for the day on which the 30-day period ends may be determined by the Administrator by following the

applicable procedures in section 7 of Method 19.

[44 FR 33613, June 11, 1979, as amended at 54 FR 6664, Feb. 14, 1989]

§ 60.47a Emission monitoring.

(a) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the opacity of emissions discharged to the atmosphere, except where gaseous fuel is the only fuel combusted. If opacity interference due to water droplets exists in the stack (for example, from the use of an FGD system), the opacity is monitored upstream of the interference (at the inlet to the FGD system). If opacity interference is experienced at all locations (both at the inlet and outlet of the sulfur dioxide control system), alternate parameters indicative of the particulate matter control system's performance are monitored (subject to the approval of the Administrator).

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

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

(2) For a facility which qualifies under the provisions of § 60.43a(d), sulfur dioxide emissions are only monitored as discharged to the atmosphere.

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

(c) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring nitrogen oxides emissions discharged to the atmosphere.

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(d) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the oxygen or carbon dioxide content of the flue gases at each location where sulfur dioxide or nitrogen oxides emissions are monitored.

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

(f) The owner or operator shall obtain emission data for at least 18 hours in at least 22 out of 30 successive boiler operating days. If this minimum data requirement cannot be met with a continuous monitoring system, the owner or operator shall supplement emission data with other monitoring systems approved by the Administrator or the reference methods and procedures as described in paragraph (h) of this section.

(g) The 1-hour averages required under paragraph § 60.13(h) are expressed in ng/J (lbs/million Btu) heat input and used to calculate the average emission rates under § 60.46a. The 1-hour averages are calculated using the data points required under § 60.13(b). At least two data points must be used to calculate the 1-hour averages.

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

(1) Method 6 shall be used to determine the SO₂ concentration at the same location as the SO₂ monitor. Samples shall be taken at 60-minute intervals. The sampling time and sample volume for each sample shall be at least 20 minutes and 0.020 dscm (0.71 dscf). Each sample represents a 1-hour average.

(2) Method 7 shall be used to determine the NO_x concentration at the same location as the NO_x monitor. Samples shall be taken at 30-minute intervals. The arithmetic average of two consecutive samples represents a 1-hour average.

(3) The emission rate correction factor, integrated bag sampling and analysis procedure of Method 3B shall be used to determine the O₂ or CO₂ concentration at the same location as the O₂ or CO₂ monitor. Samples shall be taken for at least 309 minutes in each hour. Each sample represents a 1-hour average.

(4) The procedures in Method 19 shall be used to compute each 1-hour average concentration in ng/J (lb/million Btu) heat input.

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

(1) Methods 6, 7, and 3B, as applicable, shall be used to determine O₂, SO₂, and NO_x concentrations.

(2) SO₂ or NO_x (NO), as applicable, shall be used for preparing the calibration gas mixtures (in N₂, as applicable) under Performance Specification 2 of appendix B of this part.

(3) For affected facilities burning only fossil fuel, the span value for a continuous monitoring system for measuring opacity is between 60 and 80 percent and for a continuous monitoring system measuring nitrogen oxides is determined as follows:

Fossil fuel	Span value for nitrogen oxides (ppm)
Gas	500
Liquid	500
Solid	1,000
Combination	500 (x+y)+1,000z

where:

x is the fraction of total heat input derived from gaseous fossil fuel,

y is the fraction of total heat input derived from liquid fossil fuel, and

z is the fraction of total heat input derived from solid fossil fuel.

(4) All span values computed under paragraph (b)(3) of this section for

burning combinations of fossil fuels are rounded to the nearest 500 ppm.

(5) For affected facilities burning fossil fuel, alone or in combination with non-fossil fuel, the span value of the sulfur dioxide continuous monitoring system at the inlet to the sulfur dioxide control device is 125 percent of the maximum estimated hourly potential emissions of the fuel fired, and the outlet of the sulfur dioxide control device is 50 percent of maximum estimated hourly potential emissions of the fuel fired.

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

(1) For Method 6, Method 6A or 6B (whenever Methods 6 and 3 or 3B data are used) or 6C may be used. Each Method 6B sample obtained over 24 hours represents 24 1-hour averages. If Method 6A or 6B is used under paragraph (i) of this section, the conditions under §60.46(d)(1) apply; these conditions do not apply under paragraph (h) of this section.

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

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

(4) For Method 3B, Method 3A may be used.

[44 FR 33613, June 11, 1979, as amended at 54 FR 6664, Feb. 14, 1989; 55 FR 5212, Feb. 14, 1990; 55 FR 18876, May 7, 1990]

§ 60.48a Compliance determination procedures and methods.

(a) In conducting the performance tests required in §60.8, the owner or operator shall use as reference methods and procedures the methods in appendix A of this part or the methods and procedures as specified in this section, except as provided in §60.8(b). Section 60.8(f) does not apply to this section for SO₂ and NO_x. Acceptable alternative methods are given in paragraph (e) of this section.

(b) The owner or operator shall determine compliance with the particulate matter standards in §60.42a as follows:

(1) The dry basis F factor (O₂) procedures in Method 19 shall be used to

compute the emission rate of particulate matter.

(2) For the particulate matter concentration, Method 5 shall be used at affected facilities without wet FGD systems and Method 5B shall be used after wet FGD systems.

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

(ii) For each particulate run, the emission rate correction factor, integrated or grab sampling and analysis procedures of Method 3B shall be used to determine the O₂ concentration. The O₂ sample shall be obtained simultaneously with, and at the same traverse points as, the particulate run. If the particulate run has more than 12 traverse points, the O₂ traverse points may be reduced to 12 provided that Method 1 is used to locate the 12 O₂ traverse points. If the grab sampling procedure is used, the O₂ concentration for the run shall be the arithmetic mean of all the individual O₂ concentrations at each traverse point.

(3) Method 9 and the procedures in §60.11 shall be used to determine opacity.

(c) The owner or operator shall determine compliance with the SO₂ standards in §60.43a as follows:

(1) The percent of potential SO₂ emissions (%P_s) to the atmosphere shall be computed using the following equation:

$$\%P_s = [(100 - \%R_t) (100 - \%R_g)] / 100$$

where:

%P_s=percent of potential SO₂ emissions, percent.

%R_t=percent reduction from fuel pretreatment, percent.

%R_g=percent reduction by SO₂ control system, percent.

(2) The procedures in Method 19 may be used to determine percent reduction (%R_t) of sulfur by such processes as fuel pretreatment (physical coal cleaning, hydrodesulfurization of fuel oil, etc.), coal pulverizers, and bottom and flyash interactions. This determination is optional.

(3) The procedures in Method 19 shall be used to determine the percent SO₂

reduction (%R_g of any SO₂ control system. Alternatively, a combination of an “as fired” fuel monitor and emission rates measured after the control system, following the procedures in Method 19, may be used if the percent reduction is calculated using the average emission rate from the SO₂ control device and the average SO₂ input rate from the “as fired” fuel analysis for 30 successive boiler operating days.

(4) The appropriate procedures in Method 19 shall be used to determine the emission rate.

(5) The continuous monitoring system in § 60.47a (b) and (d) shall be used to determine the concentrations of SO₂ and CO₂ or O₂.

(d) The owner or operator shall determine compliance with the NO_x standard in § 60.44a as follows:

(1) The appropriate procedures in Method 19 shall be used to determine the emission rate of NO_x.

(2) The continuous monitoring system in § 60.47a (c) and (d) shall be used to determine the concentrations of NO_x and CO₂ or O₂.

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

(1) For Method 5 or 5B, Method 17 may be used at facilities with or without wet FGD systems if the stack temperature at the sampling location does not exceed an average temperature of 160 °C (320 °F). The procedures of §§ 2.1 and 2.3 of Method 5B may be used in Method 17 only if it is used after wet FGD systems. Method 17 shall not be used after wet FGD systems if the effluent is saturated or laden with water droplets.

(2) The F_c factor (CO₂) procedures in Method 19 may be used to compute the emission rate of particulate matter under the stipulations of § 60.46(d)(1). The CO₂ shall be determined in the same manner as the O₂ concentration.

(f) Electric utility combined cycle gas turbines are performance tested for particulate matter, sulfur dioxide, and nitrogen oxides using the procedures of Method 19 (appendix A). The sulfur dioxide and nitrogen oxides emission rates from the gas turbine used in Method 19 (appendix A) calculations are determined when the gas turbine is

performance tested under subpart GG. The potential uncontrolled particulate matter emission rate from a gas turbine is defined as 17 ng/J (0.04 lb/million Btu) heat input.

[44 FR 33613, June 11, 1979, as amended at 54 FR 6664, Feb. 14, 1989; 55 FR 5212, Feb. 14, 1990]

§ 60.49a Reporting requirements.

(a) For sulfur dioxide, nitrogen oxides, and particulate matter emissions, the performance test data from the initial performance test and from the performance evaluation of the continuous monitors (including the transmissometer) are submitted to the Administrator.

(b) For sulfur dioxide and nitrogen oxides the following information is reported to the Administrator for each 24-hour period.

(1) Calendar date.

(2) The average sulfur dioxide and nitrogen oxide emission rates (ng/J or lb/million Btu) for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the emission standards; and, description of corrective actions taken.

(3) Percent reduction of the potential combustion concentration of sulfur dioxide for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the standard; and, description of corrective actions taken.

(4) Identification of the boiler operating days for which pollutant or diluent data have not been obtained by an approved method for at least 18 hours of operation of the facility; justification for not obtaining sufficient data; and description of corrective actions taken.

(5) Identification of the times when emissions data have been excluded from the calculation of average emission rates because of startup, shutdown, malfunction (NO_x only), emergency conditions (SO₂ only), or other reasons, and justification for excluding data for reasons other than startup, shutdown, malfunction, or emergency conditions.

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

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(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 continuous monitoring system.

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

(c) If the minimum quantity of emission data as required by § 60.47a is not obtained for any 30 successive boiler operating days, the following information obtained under the requirements of § 60.46a(h) is reported to the Administrator for that 30-day period:

(1) The number of hourly averages available for outlet emission rates (n_o) and inlet emission rates (n_i) as applicable.

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

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

(4) The applicable potential combustion concentration.

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

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

(1) Indicating if emergency conditions existed and requirements under § 60.46a(d) were met during each period, and

(2) Listing the following information:

(i) Time periods the emergency condition existed;

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

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

(iv) Percent reduction in emissions achieved;

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

(vi) Actions taken to correct control system malfunction.

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

(1) Indicating what percentage cleaning credit was taken for the calendar quarter, and whether the credit was determined in accordance with the provisions of § 60.48a and Method 19 (appendix A); and

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

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

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

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

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

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

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

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

(i) The owner or operator of an affected facility shall submit the written reports required under this section and subpart A to the Administrator for every calendar quarter. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter.

Subpart Db—Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

SOURCE: 52 FR 47842, Dec. 16, 1987, unless otherwise noted.

§60.40b Applicability and delegation of authority.

(a) The affected facility to which this subpart applies is each steam generating unit that commences construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 29 MW (100 million Btu/hour).

(b) Any affected facility meeting the applicability requirements under paragraph (a) of this section and commencing construction, modification, or reconstruction after June 19, 1984, but on or before June 19, 1986, is subject to the following standards:

(1) Coal-fired affected facilities having a heat input capacity between 29 and 73 MW (100 and 250 million Btu/hour), inclusive, are subject to the particulate matter and nitrogen oxides standards under this subpart.

(2) Coal-fired affected facilities having a heat input capacity greater than 73 MW (250 million Btu/hour) and meeting the applicability requirements under subpart D (Standards of performance for fossil-fuel-fired steam generators; §60.40) are subject to the particulate matter and nitrogen oxides standards under this subpart and to the sul-

fur dioxide standards under subpart D (§60.43).

(3) Oil-fired affected facilities having a heat input capacity between 29 and 73 MW (100 and 250 million Btu/hour), inclusive, are subject to the nitrogen oxides standards under this subpart.

(4) Oil-fired affected facilities having a heat input capacity greater than 73 MW (250 million Btu/hour) and meeting the applicability requirements under subpart D (Standards of performance for fossil-fuel-fired steam generators; §60.40) are also subject to the nitrogen oxides standards under this subpart and the particulate matter and sulfur dioxide standards under subpart D (§60.42 and §60.43).

(c) Affected facilities which also meet the applicability requirements under subpart J (Standards of performance for petroleum refineries; §60.104) are subject to the particulate matter and nitrogen oxides standards under this subpart and the sulfur dioxide standards under subpart J (§60.104).

(d) Affected facilities which also meet the applicability requirements under subpart E (Standards of performance for incinerators; §60.50) are subject to the nitrogen oxides and particulate matter standards under this subpart.

(e) Steam generating units meeting the applicability requirements under subpart Da (Standards of performance for electric utility steam generating units; §60.40a) are not subject to this subpart.

(f) Any change to an existing steam generating unit for the sole purpose of combusting gases containing TRS as defined under §60.281 is not considered a modification under §60.14 and the steam generating unit is not subject to this subpart.

(g) In delegating implementation and enforcement authority to a State under section 111(c) of the Act, the following authorities shall be retained by the Administrator and not transferred to a State.

- (1) Section 60.44b(f).
- (2) Section 60.44b(g).
- (3) Section 60.49b(a)(4).

§60.41b Definitions.

As used in this subpart, all terms not defined herein shall have the meaning