2.1 Fuel Burning Equipment

2.1.1 Applicability and Designation of Affected Facility

(a) The affected facility to which the provisions of this source category apply is any fuel burning equipment subject to Section 1.1 of the general provisions of this text, except as provided in paragraph (b) of this section.

(b) The provisions of this source category do not apply to facilities which are subject to the Code of Federal Regulations, Title 40, Part 60, Subparts Da, Db and Dc.

2.1.2 Test Methods and Procedures

(a) In conducting the performance tests required in Section 1.2, the owner or operator shall use as reference methods and procedures the test methods in Appendix A of this part or other methods and procedures as specified in this section, except as provided in Section 1.2(b). Acceptable alternative methods and procedures are given in paragraph (d) of this section.

(b) The owner or operator shall determine compliance with the particulate matter, SO_2, and NO_x standards as follows:

(1) The emission rate (E) of particulate matter, SO_2, or NO_x shall be computed for each run using the following equation:

$$E = CF_d\,(20.9)/(20.9 - \%O_2)$$

E = emission rate of pollutant, ng/J (lb/million Btu).

C = concentration of pollutant, ng/dscm (lb/dscf).

$\%O_2$ = oxygen concentration, percent dry basis.

F_d = factor as determined from Method 19.

(2) Method 5 shall be used to determine the particulate matter concentration (C) at affected facilities without wet flue-gas-desulfurization (FGD) systems and Method 5B shall be used to determine the particulate matter concentration (C) after FGD systems.

(i) The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf). The probe and filter holder heating systems in the sampling train may be set to provide an average gas temperature of no greater than 160°C (320°F).

(ii) The emission rate correction factor, integrated or grab sampling and analysis procedure of Method 3B shall be used to determine the O_2

concentration (%O_2). The O_2 sample shall be obtained simultaneously with, and at the same traverse points as, the particulate sample. If the grab sampling procedure is used, the O_2 concentration for the run shall be the arithmetic mean of the sample O_2 concentration at all traverse points.

(iii) If the particulate run has more than 12 traverse points, the O_2 traverse points may be reduced to 12 provided that Method 1 is used to locate the 12 O_2 traverse points.

(3) Method 9 and the procedures in Section 1.3 shall be used to determine opacity.

(4) Method 6 shall be used to determine the SO_2 concentration.

(i) The sampling site shall be the same as that selected for the particulate sample. The sampling location in the duct shall be at the centroid of the cross section or at a point no closer to the walls than 1 m (3.28 ft). The sampling time and sample volume for each sample run shall be at least 20 minutes and 0.020 dscm (0.71 dscf). Two samples shall be taken during a 1-hour period, with each sample taken within a 30-minute interval.

(ii) The emission rate correction factor, integrated sampling and analysis procedure of Method 3B shall be used to determine the O_2 concentration (%O_2). The O_2 sample shall be taken simultaneously with, and at the same point as, the SO_2 sample. The SO_2 emission rate shall be computed for each pair of SO_2 and O_2 samples. The SO_2 emission rate (E) for each run shall be the arithmetic mean of the results of the two pairs of samples.

(5) Method 7 shall be used to determine the NO_x concentration.

(i) The sampling site and location shall be the same as for the SO_2 sample. Each run shall consist of four grab samples, with each sample taken at about 15-minute intervals.

(ii) For each NO_x sample, the emission rate correction factor, grab sampling and analysis procedure of Method 3B shall be used to determine the O_2 concentration (%O_2). The sample shall be taken simultaneously with, and at the same point as, the NO_x sample.

(iii) The NO_x emission rate shall be computed for each pair of NO_x and O_2 samples. The NO_x emission rate (E) for each run shall be the arithmetic mean of the results of the four pairs of samples.

(c) When combinations of fossil fuels or fossil fuel and wood residue are fired, the owner or operator (in order to compute the prorated standard) shall determine the percentage (w, x, y, or z) of the total heat input derived from each type of fuel as follows:

(1) The heat input rate of each fuel shall be determined by multiplying the gross calorific value of each fuel fired by the rate of each fuel burned.

(2) ASTM Methods D 2015-77 (solid fuels), D 240-76 (liquid fuels), or D 1826-77 (gaseous fuels) (incorporated by reference--see Section 1.6) shall be used to determine the gross calorific values of the fuels. The method used to determine the calorific value of wood residue must be approved by the Director.

(3) Suitable methods shall be used to determine the rate of each fuel burned during each test period, and a material balance over the steam generating system shall be used to confirm the rate.

(d) The owner or operator may use the following as alternatives to the reference methods and procedures in this paragraph or in other paragraphs as specified:

(1) The emission rate (E) of particulate matter, SO_2 and NO_2 may be determined by using the F_c factor, provided that the following procedure is used:

(i) The emission rate (E) shall be computed using the following equation:

$$E = CF_c (100 / \%CO_2)$$

Where:

E = emission rate of pollutant, ng/J (lb/million Btu).

C = concentration of pollutant, ng/dscm (lb/dscf).

$\%CO_2$ = 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 O_2 and CO_2 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 ($\bar{d}$) 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 $\bar{d}$ 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 8.1 and 11.1 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 SO_2 may be determined simultaneously with the Method 5 train provided that the following changes are made:

(i) The filter and impinger apparatus in sections 6.1.1.2 and 6.1.1.3 of Method 8 is used in place of the condenser (section 6.1.1.8) of Method 5.

(ii) The temperature sensor requirement in section 6.1.1.4 of Method 8 is used in place of the temperature requirement (section 6.1.1.7) of Method 5.

(iii) All applicable procedures in Method 8 for the determination of SO_2 (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 SO_2 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 O_2 concentration ($\%O_2$) 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.

(e) The owner or operator shall determine compliance with Rule 391-3-1-.02(2)(g)(2)* or other similar sulfur-in-fuel limitation as follows:

(1) Use the procedures of Method 19 paragraph 12.5.3.2.2 and 12.5.3.2.3 to sample and analyze the fuel.

(2) Report the results on an as-fired basis. For the purpose of this procedure, "as bunkered" analysis may be considered an as-fired basis if all of the fuel in the bunker is burned in the same boiler operating day.

2.1.3 Emission and Fuel Monitoring

(a) Where required, each owner or operator shall install, calibrate, maintain, and operate continuous monitoring systems for measuring the opacity of emissions, sulfur dioxide emissions, nitrogen oxides emissions, and either oxygen or carbon dioxide except as provided in paragraph (b) of this section.

(b) Certain of the continuous monitoring system requirements under paragraph (a) of this section do not apply to owners or operators under the following conditions:

(1) For a fossil fuel-fired steam generator that burns only gaseous fossil fuel, continuous monitoring systems for measuring the opacity of emissions and sulfur dioxide emissions are not required.

(2) For a fossil fuel-fired steam generator that does not use a flue gas desulfurization device, a continuous monitoring system for measuring sulfur dioxide emissions is not required if the owner or operator monitors sulfur dioxide emissions by fuel sampling and analysis.

(3) Notwithstanding Section 1.4(b), installation of a continuous monitoring system for nitrogen oxides may be delayed until after the initial performance tests have been conducted. If the owner or operator demonstrates during the performance test that emissions of nitrogen oxides are less than 70 percent of the applicable standards, a continuous monitoring system for measuring nitrogen oxides emissions is not required. If the initial performance test results show that nitrogen oxide emissions are greater than 70 percent of the applicable standard, the owner or operator shall install a continuous monitoring system for nitrogen oxides within one year after the date of the initial performance tests and comply with all other applicable monitoring

requirements.

(4) If an owner or operator does not install any continuous monitoring systems for sulfur oxides and nitrogen oxides, as provided under paragraphs (b)(1) and (b)(3) or paragraphs (b)(2) and (b)(3) of this section, a continuous monitoring system for measuring either oxygen or carbon dioxide is not required.

(c) For performance evaluations under Section 1.4 and calibration checks under Section 1.4, the following procedures shall be used:

(1) Methods 6, 7, and 3B, as applicable, shall be used for the performance evaluations of sulfur dioxide and nitrogen oxides continuous emission monitoring systems. Methods 3A, 6C, and 7E shall be used only at the sole discretion of the source owner or operator. Acceptable alternatives for Methods 6, 7, and 3B are given in Section 2.1.2(d).

(2) Sulfur dioxide or nitric oxide, as applicable, shall be used for preparing calibration gas mixtures under Performance Specification 2 of Appendix B.

(3) For affected facilities burning fossil fuel(s), the span value for a continuous monitoring system measuring the opacity of emissions shall be 80, 90, or 100 percent and for a continuous monitoring system measuring sulfur oxides or nitrogen oxides the span value shall be determined as follows:

[In Parts Per Million]

Fossil Fuel	Span Value for Sulfur Dioxide	Span Value for Nitrogen Oxides
Gas	([1])	500
Liquid	1,000	500
Solid	1,500	500
Combination	1,000y+1,500z	500(x+y)+1000z

[1] Not Applicable

Where:

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

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

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

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

combinations of fossil fuels shall be rounded to the nearest 500 ppm.

(5) For a fossil fuel-fired steam generator that simultaneously burns fossil fuel and nonfossil fuel, the span value of all continuous monitoring systems shall be subject to the Director's approval.

(d) [Reserved]

(e) For any continuous monitoring system installed under paragraph (a) of this section, the following conversion procedures shall be used to convert the continuous monitoring data into units of the applicable standards (ng/J, lb/million Btu):

(1) When a continuous monitoring system for measuring oxygen is selected, the measurement of the pollutant concentration and oxygen concentration shall each be on a consistent basis (wet or dry). Alternative procedures approved by the Director shall be used when measurements are on a wet basis. When measurements are on a dry basis, the following conversion procedure shall be used:

$$E = CF\ [20.9 / 20.9 - \text{percent}\ O_2]$$

Where:

E, C, F, and $\%O_2$ are determined under paragraph (f) of this section.

(2) When a continuous monitoring system for measuring carbon dioxide is selected, the measurement of the pollutant concentration and carbon dioxide concentration shall each be on a consistent basis (wet or dry) and the following conversion procedure shall be used:

$$E = CF_c\ [100 / \text{percent}\ CO_2]$$

Where:

E, C, F_c and $\%CO_2$ are determined under paragraph (f) of this section.

(f) The values used in the equations under paragraphs (e) (1) and (2) of this section are derived as follows:

(1) E = pollutant emissions, ng/J (lb/million Btu).

(2) C = pollutant concentration, ng/dscm (lb/dscf), determined by multiplying the average concentration (ppm) for each one-hour period by 4.15×10^{4} M ng/dscm per ppm (2.59×10^{-9} M lb/dscf per ppm) where **M** = pollutant molecular weight, g/g-mole (lb/lb-mole). **M** = 64.07 for sulfur dioxide and 46.01 for nitrogen oxides.

(3) $\%O_2$, $\%CO_2$ = oxygen or carbon dioxide volume (expressed as percent), determined with equipment specified under paragraph (a) of this section.

(4) F, F_c = a factor representing a ratio of the volume of dry flue gases generated to the calorific value of the fuel combusted (F), and a factor representing a ratio of the volume of carbon dioxide generated to the calorific value of the fuel combusted (F_c), respectively. Values of F and F_c are given as follows:

(i) For anthracite coal as classified according to ASTM D388-77 (incorporated by reference--see Section 1.6), $F=2.723\text{x}10^{-17}$ dscm/J (10,140 dscf/million Btu and $F_c=0.532\text{x}10^{-17}$scm CO_2/J (1,980 scf CO_2/million Btu).

(ii) For subbituminous and bituminous coal as classified according to ASTM D388-77 (incorporated by reference-see Section 1.6), $F\text{-}2.637\text{x}10^{7}$ dscm/J (9,820 dscf/million Btu) and $F_c=0.486\text{x}10^{-7}$ scm CO_2/J (1,810 scf CO_2/million Btu).

(iii) For liquid fossil fuels including crude, residual, and distillate oils, F=2.476x10^{-7} dscm/J (9,220 dscf/million Btu) and F_c=0.384x10^{-7} scm CO_2/J (1,430 scf CO_2/million Btu).

(iv) For gaseous fossil fuels, F=2.347x10^{-7} dscm/J (8,740 dscf/million Btu). For natural gas, propane, and butane fuels, F_c=0.279x10^{-7} scm CO_2/J (1,040 scf CO_2/million Btu) for natural gas, 0.322x10^{-7} scm CO_2/J (1,200 scf CO_2/million Btu) for propane, and 0.338x10^{-7} scm CO_2/J (1,260 scf CO_2/million Btu) for butane.

(v) For bark F=2.589x10^{-7} dscm/J (9,640 dscf/million Btu) and F_c=0.500x10^{-7} scm CO_2/J (1,840 scf CO_2/million Btu). For wood residue other than bark F=2.492x10^{-7} dscm/J (9,280 dscf/million Btu) and F_c=0.494x10^{-7} scm CO_2/J (1,860 scf CO_2/million Btu).

(vi) For lignite coal as classified according to ASTM D388-77 (incorporated by reference--see Section 1.6), F=2.659x10^{-7} dscm/J (9,900 dscf/million Btu) and F_c=0.516x10^{-7} scm CO_2/J (1,920 scf CO_2/million Btu).

(5) The owner or operator may use the following equation to determine an **F** factor (dscm/J of dscf/million Btu) on a dry basis (if it is desired to calculate **F** on a wet basis, consult the Director) or $\mathbf{F_c}$ factor (scm CO_2/J, or scf CO_2/million Btu) on either basis in lieu of the **F** or $\mathbf{F_c}$ factors specified in paragraph (f)(4) of this section:

$$F = 10^{-6}\,\frac{[227.2\,(pct.H) + 95.5\,(pct.C) + 35.6\,(pct.S) + 8.7\,(pct.N) - 28.7\,(pct.O)]}{GCV}$$

$$F_c = \frac{2.0 \times 10^{-5}\,(pct.C)}{GCV}$$

(SI units)

$$F = \frac{10^6\,[3.64\,(\%H) + 1.53\,(\%C) + 0.57\,(\%S) + 0.14\,(\%N) - 0.46\,(\%O)]}{GCV}$$

(English units)

$$F_c = \frac{20.0\,(\%C)}{GCV} \qquad F_c = \frac{321 \times 10^3\,(\%C)}{GCV}$$

(SI units) (English units)

(i) 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 GCV by ultimate analysis of the fuel fired, using ASTM Method D3178-74 or D3176 (solid fuels) or computed from results using ASTM Method D1137-53(75), D194564(76), or D1946-77 (gaseous fuels) as applicable. (These five methods are incorporated by reference--see Section 1.6).

(ii) GCV is the gross calorific value (kJ/kg, Btu/lb) of the fuel combusted determined by the ASTM test Methods D2015-77 for solid fuels and D1826-77 for gaseous fuels as applicable. (These two methods are incorporated by reference--see Section 1.6).

(iii) For affected facilities which fire both fossil fuels and nonfossil fuels, the F or F_c value shall be subject to the Director's approval.

(6) For affected facilities firing combinations of fossil fuels or fossil fuels and wood residue, the F or F_c factors determined by paragraphs (f)(4) or (f)(5) of this section shall be prorated in accordance with the applicable formula as follows:

$$F = \sum_{i=1}^{n} X_i F_i \quad \text{or} \quad F_c = \sum_{i=1}^{n} X_i \left(F_c\right)_i$$

Where:

X_i = the fraction of total heat input derived from each type of fuel (e.g., natural gas, bituminous coal, wood residue, etc.).

F_i or $(F_c)_i$ = the applicable F or F_c factor for each fuel type determined in accordance with paragraphs (f)(5) of this section.

n = the number of fuels being burned in combination.

(g) For the purposes of reports required under Section 1.5 of this text, periods of excess emissions shall be reported as defined as follows unless otherwise stipulated by the Director:

(1) **Opacity**. For sources subject to a 20% visible emissions standard, excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds the applicable standard, except that one six-minute average per hour of up to 27 percent opacity need not be reported. For sources subject to a 40% visible emissions standard, excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds the applicable standard.

(2) **Sulfur Dioxide**. Excess emissions for affected facilities are defined as:

(i) Any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of sulfur dioxide as measured by the continuous monitoring system exceed the applicable standard.

(3) **Nitrogen Oxides**. Excess emissions for affected facilities using a continuous monitoring system for measuring nitrogen oxides are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards.

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[*] Georgia Department of Natural Resources, Rules for Air Quality Control, Chapter 391-3-1.