

## § 60.50Da

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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<sub>2</sub> and NO<sub>x</sub> span values less than or equal to 30 ppm;

(4) As an alternative to meeting the requirements of paragraph (w)(1) of this section, an owner or operator may elect to may elect to implement the following alternative data accuracy assessment procedures. For SO<sub>2</sub>, CO<sub>2</sub>, and O<sub>2</sub> CEMS and for NO<sub>x</sub> CEMS, 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<sub>2</sub> (regardless of the SO<sub>2</sub> emission level during the RATA), and for NO<sub>x</sub> when the average NO<sub>x</sub> emission rate measured by the reference method during the RATA is less than 0.100 lb/MMBtu;

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

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### § 60.50Da Compliance determination procedures and methods.

(a) In conducting the performance tests required in §60.8, the owner or operator shall use as reference methods and procedures the methods in appendix A of this part or the methods and procedures as specified in this section, except as provided in §60.8(b). Section 60.8(f) does not apply to this section for SO<sub>2</sub> and NO<sub>x</sub>. Acceptable alternative methods are given in paragraph (e) of this section.

(b) In conducting the performance tests to determine compliance with the PM emissions limits in §60.42Da, the owner or operator shall meet the requirements specified in paragraphs (b)(1) through (3) of this section.

(1) The owner or operator shall measure filterable PM to determine compliance with the applicable PM emissions limit in §60.42Da as specified in paragraphs (b)(1)(i) through (ii) of this section.

(i) The dry basis F factor (O<sub>2</sub>) procedures in Method 19 of appendix A of this part shall be used to compute the emission rate of PM.

(ii) For the PM concentration, Method 5 of appendix A of this part shall be used for an affected facility that does not use a wet FGD. For an affected facility that uses a wet FGD, Method 5B of appendix A of this part shall be used downstream of the wet FGD.

(A) 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).

(B) For each particulate run, the emission rate correction factor, integrated or grab sampling and analysis procedures of Method 3B of appendix A of this part shall be used to determine the O<sub>2</sub> concentration. The O<sub>2</sub> 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 O<sub>2</sub> traverse points may be reduced to 12 provided that Method 1 of appendix A of this part is used to locate the 12 O<sub>2</sub> traverse points. If the grab sampling procedure is used, the O<sub>2</sub> concentration

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for the run shall be the arithmetic mean of the sample O<sub>2</sub> concentrations at all traverse points.

(2) In conjunction with a performance test performed according to the requirements in paragraph (b)(1) of this section, the owner or operator of an affected facility for which construction, reconstruction, or modification commenced after May 3, 2011, shall measure condensable PM using Method 202 of appendix M of part 51.

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

(c) The owner or operator shall determine compliance with the SO<sub>2</sub> standards in §60.43Da as follows:

(1) The percent of potential SO<sub>2</sub> emissions (%Ps) to the atmosphere shall be computed using the following equation:

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

Where:

%Ps = Percent of potential SO<sub>2</sub> emissions, percent;

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

%Rg = Percent reduction by SO<sub>2</sub> control system, percent.

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

(3) The procedures in Method 19 of appendix A of this part shall be used to determine the percent SO<sub>2</sub> reduction (%R<sub>g</sub>) of any SO<sub>2</sub> 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 of appendix A of this part, may be used if the percent reduction is calculated using the average emission rate from the SO<sub>2</sub> control device and the average SO<sub>2</sub> input rate from the "as fired" fuel analysis for 30 successive boiler operating days.

(4) The appropriate procedures in Method 19 of appendix A of this part

shall be used to determine the emission rate.

(5) The CEMS in §60.49Da(b) and (d) shall be used to determine the concentrations of SO<sub>2</sub> and CO<sub>2</sub> or O<sub>2</sub>.

(d) The owner or operator shall determine compliance with the NO<sub>x</sub> standard in §60.44Da as follows:

(1) The appropriate procedures in Method 19 of appendix A of this part shall be used to determine the emission rate of NO<sub>x</sub>.

(2) The continuous monitoring system in §60.49Da(c) and (d) shall be used to determine the concentrations of NO<sub>x</sub> and CO<sub>2</sub> or O<sub>2</sub>.

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

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

(2) The F<sub>c</sub> factor (CO<sub>2</sub>) procedures in Method 19 of appendix A of this part may be used to compute the emission rate of PM under the stipulations of §60.46(d)(1). The CO<sub>2</sub> shall be determined in the same manner as the O<sub>2</sub> concentration.

(f) The owner or operator of an electric utility combined cycle gas turbine that does not meet the definition of an IGCC must conduct performance tests for PM, SO<sub>2</sub>, and NO<sub>x</sub> using the procedures of Method 19 of appendix A-7 of this part. The SO<sub>2</sub> and NO<sub>x</sub> emission rates calculations from the gas turbine used in Method 19 of appendix A-7 of this part are determined when the gas turbine is performance tested under subpart GG of this part. The potential uncontrolled PM emission rate from a

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gas turbine is defined as 17 ng/J (0.04 lb/MMBtu) heat input.

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### § 60.51Da Reporting requirements.

(a) For SO<sub>2</sub>, NO<sub>x</sub>, PM, and NO<sub>x</sub> plus CO emissions, the performance test data from the initial and subsequent performance test and from the performance evaluation of the continuous monitors (including the transmissometer) must be reported to the Administrator.

(b) For SO<sub>2</sub> and NO<sub>x</sub> the following information is reported to the Administrator for each 24-hour period.

(1) Calendar date.

(2) The average SO<sub>2</sub> and NO<sub>x</sub> emission rates (ng/J, lb/MMBtu, or lb/MWh) for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the emission standards; and, description of corrective actions taken.

(3) For owners or operators of affected facilities complying with the percent reduction requirement, percent reduction of the potential combustion concentration of SO<sub>2</sub> 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 75 percent of the hours of operation of the facility; justification for not obtaining sufficient data; and description of corrective actions taken.

(5) Identification of the times when emissions data have been excluded from the calculation of average emission rates because of startup, shutdown, or malfunction.

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

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

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

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

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

(1) The number of hourly averages available for outlet emission rates ( $n_o$ ) 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) In addition to the applicable requirements in § 60.7, the owner or operator of an affected facility subject to the opacity limits in § 60.43c(c) and conducting performance tests using Method 9 of appendix A–4 of this part shall submit excess emission reports for any excess emissions from the affected facility that occur during the reporting period and maintain records according to the requirements specified in paragraph (d)(1) of this section.

(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 (d)(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) [Reserved]

(e) If fuel pretreatment credit toward the SO<sub>2</sub> emission standard under