

**§ 75.75**

**40 CFR Ch. I (7-1-00 Edition)**

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<sub>x</sub> emission rate or NO<sub>x</sub> 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<sub>x</sub> 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, the range of operating parameters for add-on emission controls, as described in § 75.34(a) and information for verifying proper operation of the add-on emission controls, as described in § 75.34(d).

(9) The designated representative shall certify with each quarterly report that NO<sub>x</sub> emission rate values or NO<sub>x</sub> 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<sub>x</sub> emissions are not systematically underestimated.

(10) Units may qualify to use the low mass emission 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 25 tons of NO<sub>x</sub> per ozone season. The owner or operator of the unit shall meet the requirements of § 75.19, with the following exceptions:

(i) The phrase "50 tons of NO<sub>x</sub> annually" shall be replaced by the phrase "25 tons of NO<sub>x</sub> during the ozone season."

(ii) If any low mass emission unit fails to provide a demonstration that its ozone season NO<sub>x</sub> mass emissions are less than 25 tons, than 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 monitoring using an acceptable methodology by May 1 of the following year.

(11) Units may qualify to use the optional NO<sub>x</sub> mass emissions estimation protocol for gas-fired peaking units 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 part, except that the word "calendar year" shall be replaced by the word "ozone season" and the word annual in the definition of the term "capacity factor" in § 72.2 of this part, shall be replaced by the word "ozone season".

[63 FR 57507, Oct. 27, 1998, as amended at 64 FR 28627, May 26, 1999]

**§ 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<sub>x</sub> emission rate (in lbs/mmBtu) shall do so by dividing ozone season NO<sub>x</sub> mass emissions (in lbs) determined in accordance with this subpart, by heat input determined in accordance with paragraph (a) of this section.

**APPENDIX A TO PART 75—  
SPECIFICATIONS AND TEST PROCEDURES**

**1. INSTALLATION AND MEASUREMENT LOCATION**

**1.1 Pollutant Concentration and CO<sub>2</sub> or O<sub>2</sub> Monitors**

Following the procedures in section 3.1 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<sub>2</sub> pollutant concentration monitor or NO<sub>x</sub> continuous emission monitoring system (NO<sub>x</sub> pollutant concentration monitor and diluent gas monitor) will pass the relative accuracy test (see section 6 of this appendix).

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 POLLUTANT CONCENTRATION AND CO<sub>2</sub> OR O<sub>2</sub> 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 POLLUTANT CONCENTRATION AND CO<sub>2</sub> OR O<sub>2</sub> GAS 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<sub>2</sub> 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, section 2.5 or 2.4 for each of the three operating or load levels indicated in section 6.5.2 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 2.5 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 ½ 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 designated representative 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.

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<sub>2</sub>, NO<sub>x</sub>, CO<sub>2</sub>, O<sub>2</sub>, 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 readings obtained during typical unit operation are kept, to the extent practicable, between 20.0 and 80.0 percent of full-scale range of the instrument. These guidelines do not apply to: (1) SO<sub>2</sub> readings obtained during the combustion of very low sulfur fuel (as defined in §72.2 of this chapter); (2) SO<sub>2</sub> or NO<sub>x</sub> readings recorded on the high measurement range, for units with SO<sub>2</sub> or NO<sub>x</sub> emission controls and two span values; or (3) SO<sub>2</sub> or NO<sub>x</sub> readings less than 20.0 percent of full-scale on the low measurement range for a dual span unit with SO<sub>2</sub> or NO<sub>x</sub> emission controls, provided that the readings occur during periods of high control device efficiency.

#### 2.1.1 SO<sub>2</sub> Pollutant Concentration Monitors

Determine, as indicated in this section 2, the span value(s) and range(s) for an SO<sub>2</sub> 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<sub>2</sub> 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<sub>2</sub> 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 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.

(b) Alternatively, if a certified SO<sub>2</sub> CEMS is already installed, the owner or operator may make the initial MPC determination based upon quality assured historical data recorded by the CEMS. If this option is chosen, the MPC shall be the maximum SO<sub>2</sub> 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<sub>2</sub> monitor. For units with SO<sub>2</sub> emission controls, the certified SO<sub>2</sub> 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.

(c) When performing fuel sampling to determine the MPC, use ASTM Methods: ASTM D3177-89, "Standard Test Methods for Total Sulfur in the Analysis Sample of Coal and Coke"; ASTM D4239-85, "Standard Test Methods for Sulfur in the Analysis Sample of Coal and Coke Using High Temperature Tube Furnace Combustion Methods"; ASTM D4294-90, "Standard Test Method for Sulfur in Petroleum Products by Energy-Dispersive X-Ray Fluorescence Spectroscopy"; ASTM D1552-90, "Standard Test Method for Sulfur in Petroleum Products (High Temperature Method)"; ASTM D129-91, "Standard Test Method for Sulfur in Petroleum Products (General Bomb Method)"; ASTM D2622-92, "Standard Test Method for Sulfur in Petroleum Products by X-Ray Spectrometry" for sulfur content of solid or liquid fuels; ASTM D3176-89, "Standard Practice for Ultimate Analysis of Coal and Coke"; ASTM D240-87 (Reapproved 1991), "Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter"; or ASTM D2015-91, "Standard Test Method for Gross Calorific Value of Coal and Coke by the Adiabatic Bomb Calorimeter" for GCV (incorporated by reference under §75.6).

$$\text{MPC (or MEC)} = 11.32 \times 10^6 \left( \frac{\%S}{\text{GCV}} \right) \left( \frac{20.9 - \%O_{2w}}{20.9} \right) \quad (\text{Eq. A-1a})$$

or

$$\text{MPC (or MEC)} = 66.93 \times 10^6 \left( \frac{\%S}{\text{GCV}} \right) \left( \frac{\%CO_{2w}}{100} \right) \quad (\text{Eq. A-1b})$$

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 by ASTM D3177-89, ASTM D4239-85, ASTM D4294-90, ASTM D1552-90, ASTM D129-91, or ASTM D2622-92 for solid or liquid fuels (incorporated by reference under §75.6).

%O<sub>2w</sub> = Minimum oxygen concentration, percent wet basis, under typical operating conditions.

%CO<sub>2w</sub> = Maximum carbon dioxide concentration, percent wet basis, under typical operating conditions.

11.32 × 10<sup>6</sup> = Oxygen-based conversion factor in Btu/lb (ppm)/%.

66.93 × 10<sup>6</sup> = 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).

#### 2.1.1.2 Maximum Expected Concentration

(a) Make an initial determination of the maximum expected concentration (MEC) of SO<sub>2</sub> whenever: (a) SO<sub>2</sub> 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<sub>2</sub> emission controls. For units with SO<sub>2</sub> 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<sub>2</sub> 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 de-

fined in §72.2 of this chapter); or (3) fuels or blends that are used only for unit startup.

(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<sub>2</sub> CEMS is already installed, the owner or operator may make the initial MEC determination(s) based upon historical monitoring data. If this option is chosen for a unit with SO<sub>2</sub> emission controls, the MEC shall be the maximum SO<sub>2</sub> 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<sub>2</sub> emission controls, the MEC for each fuel shall be the maximum SO<sub>2</sub> 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.

$$\text{MEC} = \text{MPC} \left( \frac{100 - \text{RE}}{100} \right) \quad (\text{Eq. A-2})$$

Where:

MEC = Maximum expected concentration (ppm).

MPC = Maximum potential concentration (ppm), as determined by Eq. A-1a or A-1b.

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<sub>2</sub> 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<sub>2</sub> span concentration is ≤500 ppm, the span value may be rounded upward to the next highest multiple of 10 ppm, instead of the nearest 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<sub>2</sub> 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<sub>2</sub> pollutant concentration monitor requires a span 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<sub>2</sub> 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<sub>2</sub> concentrations. To determine whether two SO<sub>2</sub> span values are required, proceed as follows:

(a) For units with SO<sub>2</sub> 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<sub>2</sub> 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 sec-

tion 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<sub>2</sub> spans are required, the owner or operator may either use a single SO<sub>2</sub> analyzer with a dual range (i.e., low- and high-scales) or two separate SO<sub>2</sub> analyzers connected to a common sample probe and sample interface. For units with SO<sub>2</sub> 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: designate the low and high monitor ranges as separate SO<sub>2</sub> components of a single, primary SO<sub>2</sub> monitoring system; or designate the low and high monitor ranges as the SO<sub>2</sub> components of two separate, primary SO<sub>2</sub> monitoring systems; or 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<sub>2</sub> analyzer is used, designate the low and high ranges as a single SO<sub>2</sub> component of a primary SO<sub>2</sub> 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)); or, for units with SO<sub>2</sub> controls, if the default high range value is used, designate the low range analyzer as the SO<sub>2</sub> component of a primary SO<sub>2</sub> 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<sub>2</sub> 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<sub>2</sub> 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<sub>2</sub> concentration of 200 percent of the MPC for each unit operating hour in which the full-scale of the low range SO<sub>2</sub> 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<sub>2</sub> 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. For units with two SO<sub>2</sub> spans, use the low range whenever the SO<sub>2</sub> 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<sub>2</sub> 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<sub>2</sub> 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) and (b) 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<sub>2</sub> 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 imple-

ment 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<sub>2</sub> 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<sub>2</sub> spans and ranges, if the low range is exceeded, no further action is required, provided that the high range is available and is not out-of-control or out-of-service for any reason. However, if 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<sub>2</sub> 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<sub>2</sub> 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. Data from the monitor are considered invalid from the hour in which the span is adjusted until the required linearity check is passed in accordance with section 6.2 of this appendix.

#### 2.1.2 NO<sub>x</sub> Pollutant Concentration Monitors

Determine, as indicated in section 2.1.2.1, the span and range value(s) for the NO<sub>x</sub> pollutant concentration monitor so that all expected NO<sub>x</sub> concentrations can be determined and recorded accurately.

##### 2.1.2.1 Maximum Potential Concentration

(a) The maximum potential concentration (MPC) of NO<sub>x</sub> for each affected unit shall be based upon whichever fuel or blend combusted in the unit produces the highest level of NO<sub>x</sub> emissions. 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<sub>x</sub> (if an MPC of 1600 ppm for coal-fired units or 480 ppm for oil- or gas-fired units was previously selected under this part, that value may still be used, provided that the guidelines of section 2.1 of this appendix are met);

Option 2: Use the specific values based on boiler type and fuel combusted, listed in Table 2-1 or Table 2-2;

Option 3: Use NO<sub>x</sub> emission test results; or  
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<sub>x</sub> emission rate.

(b) For the purpose of providing substitute data during NO<sub>x</sub> 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<sub>x</sub> emission rate (MER), in

lb/mmBtu, by substituting the MPC for NO<sub>x</sub> in conjunction with the minimum expected CO<sub>2</sub> or maximum O<sub>2</sub> 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<sub>2</sub> (or 14.0 percent O<sub>2</sub>) for boilers or 1.0 percent CO<sub>2</sub> (or 19.0 percent O<sub>2</sub>) for combustion turbines may be used in the NO<sub>x</sub> MER calculation.

(c) Report the method of determining the initial MPC and the calculation of the maximum potential NO<sub>x</sub> emission rate in the monitoring plan for the unit.

(d) For units with add-on NO<sub>x</sub> controls (whether or not the unit is equipped with low-NO<sub>x</sub> burner technology), NO<sub>x</sub> 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. If NO<sub>x</sub> emission testing is performed, use the following guidelines. Use Method 7E from appendix A to part 60 of this chapter to measure total NO<sub>x</sub> 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<sub>2</sub> 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<sub>x</sub> concentration from all test runs as the MPC for NO<sub>x</sub>.

(e) If historical CEM data are used to determine the MPC, the data must, for uncontrolled units or units equipped with low-NO<sub>x</sub> burner technology and no other NO<sub>x</sub> controls, represent a minimum of 720 quality assured monitor operating hours, 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 a unit with add-on NO<sub>x</sub> controls (whether or not the unit is equipped with low-NO<sub>x</sub> burner 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. The highest hourly NO<sub>x</sub> concentration in ppm shall be the MPC.

TABLE 2-1.—MAXIMUM POTENTIAL CONCENTRATION FOR NO<sub>x</sub>—COAL-FIRED UNITS

Unit type	Maximum potential concentration for NO <sub>x</sub> (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 .....	( <sup>1</sup> )

<sup>1</sup> As approved by the Administrator.

TABLE 2-2.—MAXIMUM POTENTIAL CONCENTRATION FOR NO<sub>x</sub>—GAS-AND OIL-FIRED UNITS

Unit type	Maximum potential concentration for NO <sub>x</sub> (ppm)
Tangentially-fired dry bottom .....	380
Wall-fired dry bottom .....	600
Roof-fired (vertically-fired) dry bottom, arch-fired .....	550
Existing combustion turbine or combined cycle turbine .....	200
New stationary gas turbine/combustion turbine .....	50
Others .....	( <sup>1</sup> )

<sup>1</sup> As approved by the Administrator

2.1.2.2 Maximum Expected Concentration

(a) Make an initial determination of the maximum expected concentration (MEC) of NO<sub>x</sub> during normal operation for affected units with add-on NO<sub>x</sub> controls of any kind (e.g., steam injection, water injection, SCR, or SNCR). 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<sub>x</sub> 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<sub>x</sub> concentration using the testing procedures in this section; or (2) using historical CEM data over the previous 720 (or more) quality assured monitor operating hours. Include in the monitoring plan for the unit each MEC value and the method by which the MEC was determined.

(b) If NO<sub>x</sub> 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<sub>x</sub> control devices and methods used to reduce NO<sub>x</sub> emissions are operating properly. The testing shall be conducted downstream of all NO<sub>x</sub> controls. The highest point NO<sub>x</sub> con-

centration (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 representing the entire load range under stable operating conditions. The data base for the MEC shall not include any CEM data recorded during unit startup, shutdown, or malfunction or during any NO<sub>x</sub> control device malfunctions or outages. All NO<sub>x</sub> control devices and methods used to reduce NO<sub>x</sub> emissions must be operating properly during each hour. The CEM data shall be collected downstream of all NO<sub>x</sub> controls. For each type of fuel, the highest of the 720 (or more) quality assured hourly average NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> span concentration is ≤ 500 ppm, the span value may be rounded upward to the next highest multiple of 10 ppm, rather than 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<sub>x</sub> 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<sub>x</sub> pollutant concentration monitor requires a span 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<sub>x</sub> 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<sub>x</sub> concentrations. To determine whether two NO<sub>x</sub> 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  $\geq 20.0$  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<sub>x</sub> spans are required, the owner or operator may either use a single NO<sub>x</sub> analyzer with a dual range (low-and-high-scales) or two separate NO<sub>x</sub> analyzers connected to a common sample probe and sample interface. For units with add-on NO<sub>x</sub> emission controls (i.e., steam injection, water injection, SCR, or SNCR), 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: designate the low and high ranges as separate NO<sub>x</sub> components of a single, primary NO<sub>x</sub> monitoring system; or designate the low

and high ranges as the NO<sub>x</sub> components of two separate, primary NO<sub>x</sub> monitoring systems; or 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<sub>x</sub> analyzer is used, designate the low and high ranges as a single NO<sub>x</sub> component of a primary NO<sub>x</sub> 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)); or, for units with add-on NO<sub>x</sub> controls, if the default high range value is used, designate the low range analyzer as the NO<sub>x</sub> component of the primary NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> emission controls (e.g., steam injection, water injection, SCR, or SNCR), 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<sub>x</sub> 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. For units with two NO<sub>x</sub> spans, use the low range whenever

NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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) and (b) 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<sub>x</sub> 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<sub>x</sub> 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 exam-

ple of a change that may require a span and range adjustment is the installation of low-NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> spans and ranges, if the low range is exceeded, no further action is required, provided that the high range is available and is not out-of-control or out-of-service for any reason. However, if 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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 linearity test using the new calibration gases must be performed and passed. Data from the monitor are considered invalid from the hour in which the span is adjusted until the required linearity check

is passed in accordance with section 6.2 of this appendix.

### 2.1.3 CO<sub>2</sub> and O<sub>2</sub> Monitors

For an O<sub>2</sub> monitor (including O<sub>2</sub> monitors used to measure CO<sub>2</sub> emissions or percentage moisture), select a span value between 15.0 and 25.0 percent O<sub>2</sub>. For a CO<sub>2</sub> monitor installed on a boiler, select a span value between 14.0 and 20.0 percent CO<sub>2</sub>. For a CO<sub>2</sub> monitor installed on a combustion turbine, an alternative span value between 6.0 and 14.0 percent CO<sub>2</sub> may be used. An alternative O<sub>2</sub> span value below 15.0 percent O<sub>2</sub> may be used if an appropriate technical justification is included in the monitoring plan (e.g., O<sub>2</sub> 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<sub>2</sub> monitors with span values  $\geq$ 21.0 percent O<sub>2</sub>, purified instrument air containing 20.9 percent O<sub>2</sub> may be used as the high-level calibration material.

#### 2.1.3.1 Maximum Potential Concentration of CO<sub>2</sub>

For CO<sub>2</sub> pollutant concentration monitors, the maximum potential concentration shall be 14.0 percent CO<sub>2</sub> for boilers and 6.0 percent CO<sub>2</sub> 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<sub>2</sub> monitors shall only be used for the purpose of providing substitute data under this part. The CO<sub>2</sub> 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<sub>2</sub>

The owner or operator of a unit that uses a flow monitor and an O<sub>2</sub> 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 sub-

stitute data under § 75.36, determine the minimum potential O<sub>2</sub> concentration. The minimum potential O<sub>2</sub> 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<sub>2</sub> concentration shall be the lowest quality-assured hourly average O<sub>2</sub> concentration recorded in the 720 (or more) hours of data used for the determination.

#### 2.1.3.3 Adjustment of Span and Range

Adjust the span value and range of a CO<sub>2</sub> or O<sub>2</sub> monitor in accordance with section 2.1.1.5 of this appendix (insofar as those provisions are applicable), with the term “CO<sub>2</sub> or O<sub>2</sub>” applying instead of the term “SO<sub>2</sub>”. 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. 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<sup>2</sup>) at the flow monitor location.

$$\text{MPV} = \left( \frac{F_d H_f}{A} \right) \left( \frac{20.9}{20.9 - \%O_{2d}} \right) \left( \frac{100}{100 - \%H_2O} \right) \quad (\text{Eq. A-3a})$$

or

$$\text{MPV} = \left( \frac{F_c H_f}{A} \right) \left( \frac{100}{\% \text{CO}_{2d}} \right) \left( \frac{100}{100 - \% \text{H}_2\text{O}} \right) \quad (\text{Eq. A-3b})$$

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  $\text{CO}_2$ /mmBtu) from Table 1, Appendix F to this part.

$H_f$  = 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 ( $\text{ft}^2$ ) of the flue at the flow monitor location.

$\% \text{O}_{2d}$  = maximum oxygen concentration, percent dry basis, under normal operating conditions.

$\% \text{CO}_{2d}$  = minimum carbon dioxide concentration, percent dry basis, under normal operating conditions.

$\% \text{H}_2\text{O}$  = 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. Finally, calculate the "flow rate span value" (in scfh) as the product of the MPV, 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<sub>2</sub>O 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<sub>2</sub>O 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<sub>x</sub> 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<sub>2</sub>O concentration recorded in the 720 (or more) hours of data used for the determination.

#### 2.2 Design for Quality Control Testing [Reserved]

### 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<sub>2</sub> and NO<sub>x</sub> 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<sub>2</sub> or O<sub>2</sub> monitors (including O<sub>2</sub> monitors used to measure CO<sub>2</sub> emissions or percent moisture) shall not deviate from the reference value of the zero or upscale calibration gas by >0.5 percent O<sub>2</sub> or CO<sub>2</sub>, 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<sub>2</sub> and NO<sub>x</sub> 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<sub>2</sub> or O<sub>2</sub> monitors (including O<sub>2</sub> monitors

used to measure CO<sub>2</sub> 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<sub>2</sub> or O<sub>2</sub>, whichever is less restrictive.

### 3.3 Relative Accuracy

#### 3.3.1 RELATIVE ACCURACY FOR SO<sub>2</sub>

The relative accuracy for SO<sub>2</sub> pollutant concentration monitors and for SO<sub>2</sub>-diluent continuous emission monitoring systems used by units with a qualifying Phase I technology for the period during which the units are required to monitor SO<sub>2</sub> emission removal efficiency, from January 1, 1997 through December 31, 1999, shall not exceed 10.0 percent except as provided below in this section.

For affected units where the average of the monitor measurements of SO<sub>2</sub> concentration during the relative accuracy test audit is less than or equal to 250.0 ppm (or for SO<sub>2</sub>-diluent monitors, less than or equal to 0.5 lb/mmBTU), the mean value of the monitor measurements shall not exceed  $\pm 15.0$  ppm of the reference method mean value (or, for SO<sub>2</sub>-diluent monitors, not to exceed  $\pm 0.03$  lb/mmBTU for the period during which the units are required to monitor SO<sub>2</sub> emission removal efficiency, from January 1, 1997 through December 31, 1999) wherever the relative accuracy specification of 10.0 percent is not achieved.

#### 3.3.2 Relative Accuracy for NO<sub>x</sub>-Diluent Continuous Emission Monitoring Systems

(a) The relative accuracy for NO<sub>x</sub>-diluent continuous emission monitoring systems shall not exceed 10.0 percent.

(b) For affected units where the average of the monitoring system measurements of NO<sub>x</sub> emission rate during the relative accuracy test audit is less than or equal to 0.200 lb/mmBtu, the mean value of the continuous emission monitoring system measurements shall not exceed  $\pm 0.020$  lb/mmBtu of the reference method mean value whenever the relative accuracy specification of 10.0 percent is not achieved.

#### 3.3.3 RELATIVE ACCURACY FOR CO<sub>2</sub> and O<sub>2</sub> Pollutant Concentration Monitors

The relative accuracy for CO<sub>2</sub> and O<sub>2</sub> monitors shall not exceed 10.0 percent. The rel-

ative accuracy test results are also acceptable if the mean difference of the CO<sub>2</sub> or O<sub>2</sub> monitor measurements and the corresponding reference method measurement, calculated using equation A-7 of this appendix, is within 1.0 percent CO<sub>2</sub> or O<sub>2</sub>.

#### 3.3.4 RELATIVE ACCURACY FOR FLOW

Except as provided below in this section, the relative accuracy for flow monitors, where volumetric gas flow is measured in scfh, shall not exceed 15.0 percent through December 31, 1999. Beginning on January 1, 2000 (except as provided below in this section), the relative accuracy of flow monitors shall not exceed 10.0 percent.

For affected units where the average of the flow monitor measurements of gas velocity during one or more operating levels of the relative accuracy test audit is less than or equal to 10.0 fps, the mean value of the flow monitor velocity measurements shall not exceed  $\pm 2.0$  fps of the reference method mean value in fps wherever the relative accuracy specification above is not achieved.

#### 3.3.5 COMBINED SO<sub>2</sub>/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 mean difference of the reference method measurements (in percent H<sub>2</sub>O) and the corresponding moisture monitoring system measurements (in percent H<sub>2</sub>O), calculated using Equation A-7 of this appendix, are within  $\pm 1.5$  percent H<sub>2</sub>O.

#### 3.3.7 RELATIVE ACCURACY FOR NO<sub>x</sub> CONCENTRATION MONITORING SYSTEMS

(a) The following requirement applies only to NO<sub>x</sub> concentration monitoring systems (i.e., NO<sub>x</sub> pollutant concentration monitors) that are used to determine NO<sub>x</sub> mass emissions, where the owner or operator elects to monitor and report NO<sub>x</sub> mass emissions using a NO<sub>x</sub> concentration monitoring system and a flow monitoring system.

(b) The relative accuracy for NO<sub>x</sub> concentration monitoring systems shall not exceed 10.0 percent. Alternatively, for affected units where the average of the monitoring system measurements of NO<sub>x</sub> concentration during the relative accuracy test audit is less than or equal to 250.0 ppm, the mean value of the continuous emission monitoring system measurements shall not exceed  $\pm 15.0$  ppm of the reference method mean value.

### 3.4 Bias

#### 3.4.1 SO<sub>2</sub> Pollutant Concentration Monitors, NO<sub>x</sub> Concentration Monitoring Systems and NO<sub>x</sub>-Diluent Continuous Emission Monitoring Systems

SO<sub>2</sub> pollutant concentration monitors, NO<sub>x</sub>-diluent continuous emission monitoring systems and NO<sub>x</sub> concentration monitoring systems used to determine NO<sub>x</sub> 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<sub>2</sub> pollutant concentration monitors and to all NO<sub>x</sub> concentration monitoring systems, including those measuring an average SO<sub>2</sub> or NO<sub>x</sub> concentration of 250.0 ppm or less, and to all NO<sub>x</sub>-diluent continuous emission monitoring systems, including those measuring an average NO<sub>x</sub> 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 continuous emission monitoring system(s) required to perform a cycle time test shall not exceed 15 minutes.

## 4. DATA ACQUISITION AND HANDLING SYSTEMS

Automated data acquisition and handling systems shall read and record the full range of pollutant concentrations and volumetric flow from zero through span and provide a continuous, permanent record of all measurements and required information as an ASCII flat file capable of transmission both by direct computer-to-computer electronic transfer via modem and EPA-provided software and by an IBM-compatible personal computer diskette.

Data acquisition and handling systems shall also compute and record monitor calibration error; any bias adjustments to pollutant concentration, flow rate, or NO<sub>x</sub> emission rate data; and all missing data procedure statistics specified in subpart D of this part.

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 units of the standard (lb/hr of SO<sub>2</sub>, lb/mmBtu of NO<sub>x</sub>);

- (4) Predict and record NO<sub>x</sub> emission rate using the heat input rate and the NO<sub>x</sub>/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 as an ASCII flat file capable of transmission both by direct computer-to-computer electronic transfer via modem and EPA-provided software and by an IBM-compatible personal computer diskette.

## 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.

#### 5.1.4 EPA Protocol Gases

(a) EPA Protocol gases must be vendor-certified to be within 2.0 percent of the concentration specified on the cylinder label (tag value), using the uncertainty calculation procedure in section 2.1.8 of the "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards," September 1997, EPA-600/R-97/121.

(b) A copy of EPA-600/R-97/121 is available from the National Technical Information Service, 5285 Port Royal Road, Springfield, VA, 703-487-4650 and from the Office of Research and Development, (MD-77B), U.S. Environmental Protection Agency, Research Triangle Park, NC 27711.

## 5.1.5 Research Gas Mixtures

Research gas mixtures must be vendor-certified to be within 2.0 percent of the concentration specified on the cylinder label (tag value), using the uncertainty calculation procedure in section 2.1.8 of the "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards," September 1997, EPA-600/R-97/121. 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<sub>2</sub>, NO<sub>x</sub>, CO<sub>2</sub>, and O<sub>2</sub> 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<sub>2</sub>, NO<sub>x</sub>, CO<sub>2</sub>, and O<sub>2</sub> 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<sub>2</sub>, NO<sub>x</sub>, CO<sub>2</sub>, and O<sub>2</sub> 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<sub>2</sub>, NO<sub>x</sub>, CO<sub>2</sub>, and O<sub>2</sub> monitors, as appropriate.

## 6. CERTIFICATION TESTS AND PROCEDURES

## 6.1 Pretest Preparation

Install the components of the continuous emission monitoring system (i.e., pollutant concentration monitors, CO<sub>2</sub> or O<sub>2</sub> 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.

## 6.2 Linearity Check (General Procedures)

Check the linearity of each SO<sub>2</sub>, NO<sub>x</sub>, CO<sub>2</sub>, and O<sub>2</sub> 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<sub>2</sub> or NO<sub>x</sub> span value for a particular monitor range is ≤30 ppm, that range is exempted from the linearity test requirements of this part. For units using emission controls and other units using both a high and a low span, perform a linearity check on both the low- and high-scales for initial certification. 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 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

Measure the calibration error of each SO<sub>2</sub> monitor, each NO<sub>x</sub> monitor and each CO<sub>2</sub> or O<sub>2</sub> 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 extended 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 non-consecutive 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. In addition, repeat the procedure for SO<sub>2</sub> and NO<sub>x</sub> 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<sub>2</sub> or O<sub>2</sub> 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 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

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 extended 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 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).

#### 6.4 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 (see also Figure 6 at the end of this appendix). Use a zero-level and a high-level calibration gas (as defined in section 5.2 of this appendix) alternately. To determine the upscale elapsed time, 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 stable starting gas value and start time, using the data acquisition and handling system (DAHS). Next, allow the monitor to measure the concentration of flue gas emissions until the response stabilizes. Record the stable ending stack emissions value and the end time of the test using the DAHS. Determine the upscale elapsed time as the time it takes for 95.0 percent of the step change to be achieved between the stable starting gas value and the stable ending stack emissions value. Then repeat the procedure, starting by injecting the high-level gas concentration to determine the downscale elapsed time, which is the time it takes for 95.0 percent of the step change to be achieved between the stable starting gas value and the stable ending stack emissions value. End the downscale test by measuring the stable concentration of flue gas emissions. Record the stable starting and ending monitor values, the start and end times, and the downscale elapsed time for the monitor using the DAHS. 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. (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. Report the slower of the two elapsed times (upscale or downscale) as the cycle time for the analyzer. (See Figure

5 at the end of this appendix.) For the NO<sub>x</sub>-diluent continuous emission monitoring system test and SO<sub>2</sub>-diluent continuous emission monitoring system test, record and report the longer cycle time of the two component analyzers as the system cycle time. For time-shared systems, this procedure must be done at all 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, add together the longest cycle time obtained at each of the probe locations. Report the sum of the longest cycle time at each of the probe locations 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 as the cycle time for each of the time-shared systems. For monitors with dual ranges, report the test results from on the range giving the longer cycle time. 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 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<sub>2</sub> pollutant concentration monitor (including O<sub>2</sub> monitors used to determine CO<sub>2</sub> pollutant concentration), each SO<sub>2</sub> pollutant concentration monitor, each NO<sub>x</sub> concentration monitoring system used to determine NO<sub>x</sub> mass emissions, each flow monitor, each NO<sub>x</sub>-diluent continuous emission monitoring system, each O<sub>2</sub> or CO<sub>2</sub> diluent monitor used to calculate heat input, each moisture monitoring system and each SO<sub>2</sub>-diluent continuous emission monitoring system. For NO<sub>x</sub> concentration monitoring systems used to determine NO<sub>x</sub> mass emissions, as defined in § 75.71(a)(2), use the same general RATA procedures as for SO<sub>2</sub> pollutant concentration monitors; however, use the reference meth-

ods for NO<sub>x</sub> concentration specified in section 6.5.10 of this appendix:

(a) Except as provided 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 normal 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). When relative accuracy test audits are performed on continuous emission monitoring systems or component(s) 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 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<sub>2</sub> or NO<sub>x</sub> controls 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), 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.

(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 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<sub>2</sub> or CO<sub>2</sub> pollutant concentration monitor, each flow monitor, each CO<sub>2</sub> or O<sub>2</sub> diluent monitor used to determine heat input, each NO<sub>x</sub> concentration monitoring system used to determine NO<sub>x</sub> mass emissions, as defined in § 75.71(a)(2), each moisture monitoring system and each NO<sub>x</sub>-diluent continuous emission monitoring system, calculate the relative accuracy, in accordance with section 7.3 or 7.4 of this appendix, as applicable. In addition (except for CO<sub>2</sub>, O<sub>2</sub>, SO<sub>2</sub>-diluent 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<sub>2</sub> or CO<sub>2</sub> pollutant concentration monitor, each CO<sub>2</sub> or O<sub>2</sub> diluent monitor used to determine heat input, each NO<sub>x</sub>-diluent continuous emission monitoring system, each NO<sub>x</sub> concentration monitoring system used to determine NO<sub>x</sub> mass emissions, as defined in § 75.71(a)(2), and each SO<sub>2</sub>-diluent continuous emission monitoring system, at the normal load 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 have been designated as normal, the RATAs may be done at either load 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 for flow monitors on bypass stacks/ducts and peaking units, 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 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 combinations for the units exhausting to the common stack. Select the three exhaust gas velocities such that the audit points at adjacent load levels (i.e., low and mid or mid and high), in megawatts (or in thousands of lb/hr of steam production), 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 of this appendix.

(c) Flow monitor recertification RATAs shall be done at three load level(s), unless otherwise specified in paragraph (b) 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) specified in section 2.3.1.3 of appendix B to this part.

##### 6.5.2.1 Range of Operation and Normal Load Level(s)

(a) The owner or operator shall determine the upper and lower boundaries of the "range of operation" for each unit (or combination of units, for common stack configurations) that uses CEMS to account for its emissions and for each unit that uses the optional fuel flow-to-load quality assurance test in section 2.1.7 of appendix D to this part. The lower boundary of the range of operation of a unit shall be the minimum safe, stable load. For common stacks, the minimum safe, stable load shall be the lowest of 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 unit 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 or thousands of lb/hr of steam load.

(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 to 60.0 percent) of the range of operation; and the "high" operating level shall be the upper end (60.0 to 100.0 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) The owner or operator shall identify, for each affected unit or common stack (except for peaking units), the "normal" load level or levels (low, mid or high), based on the operating history of the unit(s). This requirement becomes effective on April 1, 2000; however, the owner or operator may choose to comply with this requirement prior to April 1, 2000. 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.

(d) Based on the analysis of the historical load data the owner or operator shall 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, 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.

(e) Beginning on April 1, 2000, 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 of steam production, in the electronic quarterly report required under §75.64. Except for peaking units, the owner or operator shall indicate, in the electronic quarterly report (as part of 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 Flow RATA Results

For each multi-load 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 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.

#### 6.5.3 CO<sub>2</sub> POLLUTANT CONCENTRATION MONITORS

Perform relative accuracy test audits for each CO<sub>2</sub> monitor (measuring in percent CO<sub>2</sub>) at a normal operating level for the unit (or combined units, if common stack).

#### 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<sub>2</sub> and NO<sub>x</sub> continuous emission monitoring systems, Performance Specification 3 in appendix B of part 60 of this chapter for CO<sub>2</sub> or O<sub>2</sub> 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 3.2 of Performance Specification 2 ("PS No. 2") in appendix B to part 60 of this chapter (for SO<sub>2</sub>, NO<sub>x</sub>, and moisture monitoring system RATAs), Performance Specification 3 in appendix B to part 60 of this chapter (for O<sub>2</sub> and CO<sub>2</sub> 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. Unless otherwise specified, use only codified versions of PS No. 2 revised as of July 1, 1995, July 1, 1996 or July 1, 1997. 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 3.2 of PS No. 2 allows the use of a short reference method measurement line (with three points located at 0.4, 1.0, 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 sec-

tion 3.2 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 3.2 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).

## 6.5.6.1 Stratification Test

(a) With the unit(s) operating under steady-state conditions at normal load, as defined in section 6.5.2.1 of this appendix, use a traversing gas sampling probe to measure the pollutant (SO<sub>2</sub> or NO<sub>x</sub>) and diluent (CO<sub>2</sub> or O<sub>2</sub>) 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 ( $\pm 3.0$  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<sub>x</sub>, SO<sub>2</sub>, and CO<sub>2</sub> (or O<sub>2</sub>) concentrations at each of the individual traverse points. Then, calculate the arithmetic average NO<sub>x</sub>, SO<sub>2</sub>, and CO<sub>2</sub> (or O<sub>2</sub>) 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, as

defined in section 6.5.2.1 of this appendix, use a traversing gas sampling probe to measure the pollutant (SO<sub>2</sub> or NO<sub>x</sub>) and diluent (CO<sub>2</sub> or O<sub>2</sub>) concentrations at three points. The points shall be located according to the specifications for the long measurement line in section 3.2 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 ( $\pm 3.0$  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<sub>x</sub>, SO<sub>2</sub>, and CO<sub>2</sub> (or O<sub>2</sub>) concentrations at each of the individual traverse points. Then, calculate the arithmetic average NO<sub>x</sub>, SO<sub>2</sub>, and CO<sub>2</sub> (or O<sub>2</sub>) 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 3.2 of PS No. 2 may be used in lieu of the long measurement line prescribed in section 3.2 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  $\pm 10.0$  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  $\pm 5$  ppm or  $\pm 0.5$  percent CO<sub>2</sub> (or O<sub>2</sub>) 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 appen-

dix, show that the concentration at each individual traverse point differs by no more than  $\pm 5.0$  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  $\pm 3$  ppm or  $\pm 0.3$  percent CO<sub>2</sub> (or O<sub>2</sub>) 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 § 75.56(a)(7) or § 75.59(a)(7), as applicable.

#### 6.5.7 Sampling Strategy

(a) Conduct the reference method tests 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<sub>2</sub> or O<sub>2</sub> monitor, flow monitor, and SO<sub>2</sub> or NO<sub>x</sub> continuous emission monitoring system 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<sub>x</sub>-diluent or SO<sub>2</sub>-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 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). 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 three test runs (whichever is less restrictive). Successive flow RATA runs may be performed without waiting in-between runs. If an O<sub>2</sub>-diluent monitor is used as a CO<sub>2</sub> continuous emission monitoring system, perform a CO<sub>2</sub> system RATA (i.e., measure CO<sub>2</sub>, rather than O<sub>2</sub>, with the reference method). 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 reference method. 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 §§ 75.56(a)(5)(ix) and 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<sub>2</sub> or NO<sub>x</sub> continuous emission monitoring system data (in lb/mmBtu) and volumetric flow rate data with the 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<sub>2</sub>, 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 from appendix A to part 60 of this chapter or their approved alternatives are the reference methods for performing relative accuracy test audits: Method 1 or 1A for siting; Method 2 or its allowable alternatives in appendix A to part 60 of this chapter (except for Methods 2B and 2E) for stack gas velocity and volumetric flow rate; Methods 3, 3A, or 3B for O<sub>2</sub> or CO<sub>2</sub>; Method 4 for moisture; Methods 6, 6A, or 6C for SO<sub>2</sub>; Methods 7, 7A, 7C, 7D or 7E for NO<sub>x</sub>, excluding the exception in section 5.1.2 of Method 7E. When using Method 7E for measuring NO<sub>x</sub> concentration, total NO<sub>x</sub>, both NO and NO<sub>2</sub>, must be measured.

### 7. CALCULATIONS

#### 7.1 Linearity Check

Analyze the linearity data for pollutant concentration and CO<sub>2</sub> or O<sub>2</sub> 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.

$$LE = \frac{|R-A|}{R} \times 100$$

(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:

$$CE = \frac{|R-A|}{S} \times 100$$

(Eq. A-5)  
where,

CE = Calibration error as a percentage of the span of the instrument.

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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:

$$CE = \frac{|R-A|}{S} \times 100 \quad (\text{Eq. A-6})$$

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<sub>2</sub> and CO<sub>2</sub> Pollutant Concentration Monitors, SO<sub>2</sub>-Diluent Continuous Emission Monitoring Systems, and Flow Monitors**

Analyze the relative accuracy test audit data from the reference method tests for SO<sub>2</sub> and CO<sub>2</sub> pollutant concentration monitors, SO<sub>2</sub>-diluent continuous emission monitoring systems (lb/mmBtu) used by units with a qualifying Phase I technology for the period during which the units are required to monitor SO<sub>2</sub> emission removal efficiency, from January 1, 1997 through December 31, 1999, 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, d, of a data set as follows.

$$\bar{d} = \frac{1}{n} \sum_{i=1}^n d_i$$

(Eq. A-7)

where,

n = Number of data points.

$\sum_{i=1}^n d_i$  = Algebraic sum of the individual differences d<sub>i</sub>.

d<sub>i</sub> = The difference between a reference method value and the corresponding continuous emission monitoring system value (RM<sub>i</sub>-CEM<sub>i</sub>) at a given point in time i.

When calculating the arithmetic mean of the difference of a flow monitor data set, be sure to correct the monitor measurements for moisture if applicable.

**7.3.2 STANDARD DEVIATION**

Calculate the standard deviation, S<sub>d</sub>, of a data set as follows:

$$S_d = \sqrt{\frac{\sum_{i=1}^n d_i^2 - \left[ \frac{\left( \sum_{i=1}^n d_i \right)^2}{n} \right]}{n-1}}$$

(Eq. A-8)

**7.3.3 CONFIDENCE COEFFICIENT**

Calculate the confidence coefficient (one-tailed), cc, of a data set as follows.

$$cc = t_{0.025} \frac{S_d}{\sqrt{n}}$$

(eq. A-9)

where,

t<sub>0.025</sub> = t value (see table 7-1).

**TABLE 7-1—T-VALUES**

	n-1	t <sub>0.025</sub>	n-1	t <sub>0.025</sub>	n-1	t <sub>0.025</sub>
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

TABLE 7-1—T-VALUES—Continued

n-1	t <sub>0.025</sub>	n-1	t <sub>0.025</sub>	n-1	t <sub>0.025</sub>
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.

$$RA = \frac{|d| + |cc|}{RM} \times 100$$

(Eq. A-10)

where,

RM = Arithmetic mean of the reference - method values.

|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<sub>x</sub> Continuous Emission Monitoring Systems

Analyze the relative accuracy test audit data from the reference method tests for NO<sub>x</sub> continuous emissions monitoring system as follows.

7.4.1 DATA PREPARATION

If C<sub>NO<sub>x</sub></sub>, the NO<sub>x</sub> concentration, is in ppm, multiply it by 1.194 × 10<sup>-7</sup> (lb/dscf)/ppm to convert it to units of lb/dscf. If C<sub>NO<sub>x</sub></sub> is in mg/dscm, multiply it by 6.24 × 10<sup>-8</sup> (lb/dscf)/(mg/dscm) to convert it to lb/dscf. Then, use the diluent (O<sub>2</sub> or CO<sub>2</sub>) reference method results for the run and the appropriate F or F<sub>c</sub> factor from table 1 in appendix F of this part to convert C<sub>NO<sub>x</sub></sub> 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<sub>x</sub> EMISSION RATE (MONITORING SYSTEM)

For each test run in a data set, calculate the average NO<sub>x</sub> 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<sub>x</sub> continuous emission monitoring system. In using equation A-7, "d" is, for each run, the difference between the NO<sub>x</sub> emission rate values (in lb/mmBtu) obtained

from the reference method data and the NO<sub>x</sub> continuous emission monitoring system.

7.5 Relative Accuracy for Combined SO<sub>2</sub>/Flow [Reserved]

7.6 Bias Test and Adjustment Factor

Test the following relative accuracy test audit data sets for bias: SO<sub>2</sub> pollutant concentration monitors; flow monitors; NO<sub>x</sub> concentration monitoring systems used to determine NO<sub>x</sub> mass emissions, as defined in §75.71(a)(2); and NO<sub>x</sub>-diluent continuous emission monitoring systems, using the procedures outlined in section 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 difference, d, of the data set using equation A-7 of this appendix. To calculate bias for an SO<sub>2</sub> pollutant concentration monitor, "d" is, for each paired data point, the difference between the SO<sub>2</sub> concentration value (in ppm) obtained from the reference method and the monitor. To calculate bias for a flow monitor, "d" 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<sub>x</sub> continuous emission monitoring system, "d" is, for each paired data point, the difference between the NO<sub>x</sub> 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<sub>d</sub>, 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, 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, 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:

$$CEM_i^{\text{Adjusted}} = CEM_i^{\text{Monitor}} \times \text{BAF} \quad (\text{Eq. A-11})$$

Where:

$CEM_i^{\text{Monitor}}$  = Data (measurement) provided by the monitor at time  $i$ .

$CEM_i^{\text{Adjusted}}$  = Data value, adjusted for bias, at time  $i$ .

BAF = Bias adjustment factor, defined by:

$$\text{BAF} = 1 + \frac{|\bar{d}|}{CEM_{\text{avg}}} \quad (\text{Eq. A-12})$$

Where:

BAF = Bias adjustment factor, calculated to the nearest thousandth.

$d$  = Arithmetic mean of the difference obtained during the failed bias test using Equation A-7.

$CEM_{\text{avg}}$  = Mean of the data values provided by the monitor during the failed bias test.

(b) For single-load RATAs of  $\text{SO}_2$  pollutant concentration monitors,  $\text{NO}_x$  concentration monitoring systems, and  $\text{NO}_x$ -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  $\text{NO}_x$  concentration CEMS or an  $\text{SO}_2$  CEMS or a  $\text{NO}_x$ -diluent CEMS installed on a low-emitting affected unit (i.e., average  $\text{SO}_2$  or  $\text{NO}_x$  concentration during the RATA  $\leq 250$  ppm or average  $\text{NO}_x$  emission rate  $\leq 0.200$  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 sec-

ond 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  $\text{SO}_2$ , the flow rate, the average  $\text{NO}_x$  emission rate, the unit heat input, and the calculated mass emissions of  $\text{SO}_2$  and  $\text{CO}_2$  during the quarter and calendar year, as specified in subpart G of this part. In addition, when using a  $\text{NO}_x$  concentration monitoring system and a flow monitor to calculate  $\text{NO}_x$  mass emissions under subpart H of this part, use bias-adjusted values for  $\text{NO}_x$  concentration and flow rate in the mass emission calculations and use bias-adjusted  $\text{NO}_x$  concentrations to compute the appropriate substitution values for  $\text{NO}_x$  concentration in the missing data routines under subpart D of this part.

#### 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  $R_{\text{ref}}$ , 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  $R_{\text{ref}}$  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 requirements of this section shall become effective as of April 1, 2000. The reference flow-to-load ratio shall be calculated as follows:

$$R_{ref} = \frac{Q_{ref}}{L_{avg}} \times 10^{-5} \quad (\text{Eq. A-13})$$

Where:

$R_{ref}$  = Reference value of the flow-to-load ratio, from the most recent normal-load flow RATA, scfh/megawatts or scfh/1000 lb/hr of steam.

$Q_{ref}$  = 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 or 1000 lb/hr of steam.

(b) In Equation A-13, for a common stack,  $L_{avg}$  shall be the sum of the operating loads of all units that discharge through the stack. For a unit that discharges its emissions through multiple stacks (except for a discharge configuration consisting of a main stack and a bypass stack),  $Q_{ref}$  will be the sum of the total volumetric flow rates that discharge through all of the stacks. 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<sub>2</sub> 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<sub>2</sub> or O<sub>2</sub>) 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:

$$(GHR)_{ref} = \frac{(\text{Heat Input})_{avg}}{L_{avg}} \times 1000 \quad (\text{Eq. A-13a})$$

Where:

$(GHR)_{ref}$  = Reference value of the gross heat rate at the time of the most recent normal-load flow RATA, Btu/kwh or Btu/lb steam load.

$(\text{Heat Input})_{avg}$  = Average hourly heat input during the normal-load flow RATA, as determined using the applicable equation in appendix F to this part, mmBtu/hr.

$L_{avg}$  = Average unit load during the normal-load flow RATA, megawatts or 1000 lb/hr of steam.

(d) In the calculation of  $(\text{Heat Input})_{avg}$ , 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.

7.8 Flow-to-Load Test Exemptions

The requirements of this section apply beginning on April 1, 2000. For complex stack configurations (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. 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.

FIGURE 1 TO APPENDIX A—LINEARITY ERROR DETERMINATION

Day	Date and time	Reference value	Monitor value	Difference	Percent of reference value
Low-level:					

FIGURE 1 TO APPENDIX A—LINEARITY ERROR DETERMINATION—Continued

Day	Date and time	Reference value	Monitor value	Difference	Percent of reference value
Mid-level:					
High-level:					

FIGURE 2 TO APPENDIX A—RELATIVE ACCURACY DETERMINATION (POLLUTANT CONCENTRATION MONITORS)

Run No.	Date and time	SO <sub>2</sub> (ppm <sup>c</sup> )			Date and time	CO <sub>2</sub> (Pollutant) (ppm <sup>c</sup> )		
		RM <sup>a</sup>	M <sup>b</sup>	Diff		RM <sup>a</sup>	M <sup>b</sup>	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).								

<sup>a</sup>RM means "reference method data."  
<sup>b</sup>M means "monitor data."  
<sup>c</sup>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<sub>x</sub>/DILUENT COMBINED SYSTEM)

Run No.	Date and time	Reference method data		NO <sub>x</sub> system (lb/mmBtu)		
		NO <sub>x</sub> ( ) <sup>a</sup>	O <sub>2</sub> /CO <sub>2</sub> %	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).						

<sup>a</sup> Specify units: ppm, lb/dscf, mg/dscm.

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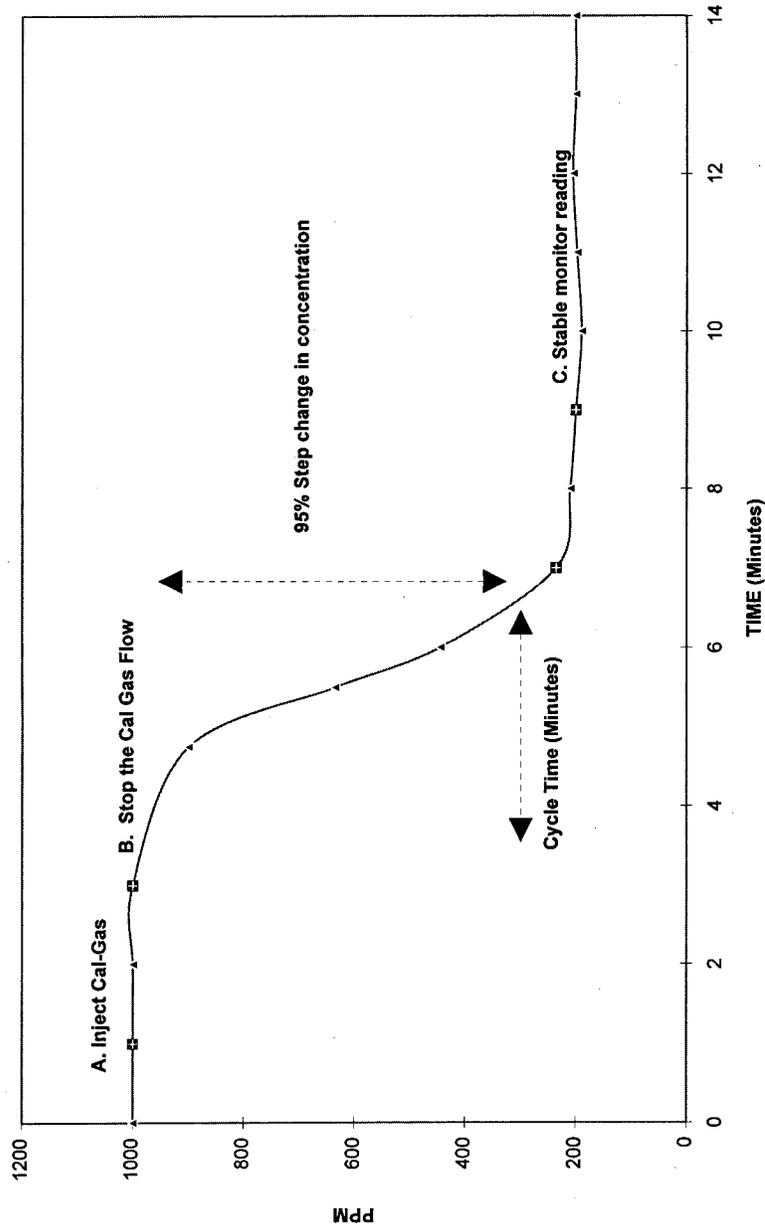
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FIGURE 5—CYCLE TIME

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 6. Downscale Cycle Time Test



A. To determine the downscale cycle time, inject a high level calibration gas into the port leading to the calibration cell or thimble.

B. Allow the analyzer to stabilize. Record the stabilized value. Stop the calibration gas flow and allow the monitor to measure the

flue gas emissions until the response stabilizes.

C. Record the stabilized value. A stable reading is achieved when the concentration reading deviates less than 6% from the measured average concentration in 6 minutes or if it deviates less than 2% of the monitor's span value in 2 minutes. (Owners and operators of units that do not record data in 1 minute or 3 minute intervals may petition the Administrator under section 75.66 for alternative stabilization criteria.)

D. Determine the step change. The step change is equal to the difference between the stabilized calibration gas value (Point B) and the final stable value (Point C). Take 95% of the step change value and subtract the result from the stabilized calibration gas value (Point B). Determine the time at which 95% of the step change occurred (Point D).

E. Determine the cycle time. The cycle time is equal to the downscale elapsed time, i.e. the time at which 95% of the step change occurred (point D) minus the time at which the calibration gas flow was stopped (Point B). In this example, cycle time=(6.5-4)=2.5 minutes (Report as 3 minutes).

F. To determine the cycle time for the upscale test, inject a zero scale calibration gas into the probe and repeat the procedures described above, except that 95% of the step change in concentration is added to the stabilized calibration gas value. Afterwards, compare the two cycle times achieved for both the upscale and downscale tests. The longer of these two times equals the cycle time for the analyzer.

[58 FR 3701, Jan. 11, 1993, as amended at 60 FR 26541-26546, 26569-26570, May 17, 1995; 61 FR 25582, May 22, 1996; 61 FR 59162, Nov. 20, 1996; 63 FR 57512, Oct. 27, 1998; 64 FR 28631-28643, May 26, 1999; 64 FR 37582, July 12, 1999]

#### 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.

##### 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.

##### 1.2 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<sub>2</sub> or NO<sub>x</sub> 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<sub>2</sub> or NO<sub>x</sub> 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 section 2.1.5.1 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 unit manufacturer's 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<sub>x</sub> emission rate testing. Keep a copy of all data and results from the initial and from the most recent NO<sub>x</sub> 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<sub>2</sub> 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.

For units with add-on emission controls and dual-span or auto-ranging monitors, and other units that use the maximum expected concentration to determine calibration gas values, perform the daily calibration error tests on each scale that has been used since the previous calibration error test. For example, if the pollutant concentration has not exceeded the low-scale value (based on the maximum expected concentration) since the previous calibration error test, the calibration error test may be performed on the low-scale only. If, however, the concentration has exceeded the low-scale span value for one hour or longer since the previous calibration error test, perform the calibration error test on both the low- and high-scales.

**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 oper-

ation 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, a successful on-line calibration error test of the monitoring system must be completed no later than 26 unit operating hours after each off-line calibration error test used for data validation.

##### 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<sub>2</sub> or O<sub>2</sub> 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<sub>2</sub> or NO<sub>x</sub> pollutant concentration monitor exceeds 5.0 percent of the span value (or exceeds 10 ppm, for span values <200 ppm), when the calibration error of a CO<sub>2</sub> or O<sub>2</sub> monitor (including O<sub>2</sub> monitors used to measure CO<sub>2</sub> emissions or percent moisture) exceeds 1.0 percent O<sub>2</sub> or CO<sub>2</sub>, or when the calibration error of a flow monitor or a moisture sensor exceeds 6.0 percent of the span value, which is twice the ap-

plicable 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, is  $\leq 0.02$  inches of water. 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<sub>x</sub>-diluent continuous emission monitoring system 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.

#### 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) Beginning on January 1, 1999, for a monitoring system that has passed the off-line calibration demonstration, if an on-line daily calibration error test of the same monitoring system is not conducted and passed within 26 unit operating hours of an off-line calibration error test that is used for data

validation, then data from that monitoring system are invalid, beginning with the 27th unit operating hour following that off-line calibration error test.

**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 applied 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

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<sub>2</sub> and NO<sub>x</sub> pollutant concentration monitor and each primary and redundant backup CO<sub>2</sub> or O<sub>2</sub> monitor (including O<sub>2</sub> monitors used to measure CO<sub>2</sub> 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(f) 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)(I). However, if, for any trial injection, the specification in § 75.20(b)(3)(vii)(E)(I) is not met, the trial injection shall be counted as an aborted linearity check.

(b) 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.

(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<sub>x</sub>-diluent or SO<sub>2</sub>-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). 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.

#### 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 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 con-

ducted 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.* The provisions of this section apply beginning on April 1, 2000. Unless exempted by an approved petition in accordance with 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  $\pm 10.0$  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.

$$R_h = \frac{Q_h}{L_h} \times 10^{-5} \quad (\text{Eq. B-1})$$

Where:

$R_h$  = Hourly value of the flow-to-load ratio, scfh/megawatts or scfh/1000 lb/hr of steam load.

$Q_h$  = Hourly stack gas volumetric flow rate, as measured by the flow rate monitor, scfh.

$L_h$  = Hourly unit load, megawatts or 1000 lb/hr of steam; must be within  $\pm 10.0$  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 (except when one of the stacks is a bypass stack) or that monitors its emissions

in multiple breechings,  $Q_h$  will be the combined hourly volumetric flow rate for all of the stacks or ducts. 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  $\text{SO}_2$  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 ( $\text{CO}_2$  or  $\text{O}_2$ ) 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:

$$(\text{GHR})_h = \frac{(\text{Heat Input})_h}{L_h} \times 1000 \quad (\text{Eq. B-1a})$$

where:

$(\text{GHR})_h$  = Hourly value of the gross heat rate, Btu/kwh or Btu/lb steam load.

$(\text{Heat Input})_h$  = 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 or 1000 lb/hr of steam; must be within  $\pm 10.0$  percent of  $L_{\text{avg}}$  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  $(\text{Heat Input})_h$ , provided that all of the heat input 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 recorded hourly average flow rates. 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 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 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  $R_{\text{ref}}$ , 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  $R_{\text{ref}}$  shall always be based upon the most recent normal-load RATA, even if that RATA was performed in the calendar quarter being evaluated.

$$E_h = \frac{|R_{\text{ref}} - R_h|}{R_{\text{ref}}} \times 100 \quad (\text{Eq. B-2})$$

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  $\pm 10.0$  percent of  $L_{\text{avg}}$ .

$R_{\text{ref}}$  = 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  $R_{\text{ref}}$  and  $R_h$  if the flow-to-load ratio is being evaluated, and use  $(\text{GHR})_{\text{ref}}$  and  $(\text{GHR})_h$  if the gross heat rate is being evaluated. Finally, calculate  $E_r$ , 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  $E_r$  is less than or equal to: (1) 15.0 percent, if  $L_{\text{avg}}$  for the most recent normal-load flow RATA is  $\geq 60$  megawatts (or  $\geq 500$  klb/hr of steam) and if unadjusted flow rates were used in the calculations; or (2) 10.0 percent, if  $L_{\text{avg}}$  for the most recent normal-load flow RATA is  $\geq 60$  megawatts (or  $\geq 500$  klb/hr of steam) and if bias-adjusted flow rates were used in the calculations; or (3) 20.0 percent, if  $L_{\text{avg}}$  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  $L_{\text{avg}}$  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  $E_r$  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  $E_r$ , after excluding all non-representative hourly flow rates.

(c) *Recalculation of  $E_r$* . If the owner or operator chooses to recalculate  $E_r$ , 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);

(2) For a unit that is equipped with an SO<sub>2</sub> scrubber and which always discharges its flue gases to the atmosphere through a single stack, any hour in which the SO<sub>2</sub> 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,  $E_r$  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,  $E_r$  is still above the applicable limit, the monitor shall be declared out-of-control, beginning with the first hour of the quarter following the quarter in which  $E_r$  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 two weeks of the end of the calendar quarter for which the  $E_r$  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)), 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. Data from the monitor shall remain invalid until a probationary calibration error test of the monitor is passed following completion of all corrective actions, at which point data from the monitor are conditionally valid. The owner or operator then either may 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-level 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  $E_r$  is outside of the applicable limit. Data from the monitor remain invalid until the required RATA has been passed.

#### 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 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. 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  $\pm 5.0$  percent of the average load during the RATA and that the diluent gas ( $\text{CO}_2$  or  $\text{O}_2$ ) concentration be maintained within  $\pm 0.5$  percent  $\text{CO}_2$  or  $\text{O}_2$  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. However, if  $E_f$  is outside the applicable limit, all conditionally valid data recorded by the flow monitor 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  $\text{SO}_2$  pollutant concentration monitor, flow monitor,  $\text{CO}_2$  pollutant concentration monitor (including  $\text{O}_2$  monitors used to determine  $\text{CO}_2$  emissions),  $\text{CO}_2$  or  $\text{O}_2$  diluent monitor used to determine heat input, moisture monitoring system,  $\text{NO}_x$  concentration monitoring system,  $\text{NO}_x$ -diluent continuous emission monitoring system, or  $\text{SO}_2$ -diluent continuous emission monitoring system. 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  $\text{SO}_2$  pollutant concentration monitors,  $\text{CO}_2$  pollutant concentration monitors (including  $\text{O}_2$  monitors used to determine  $\text{CO}_2$  emissions),  $\text{CO}_2$  or  $\text{O}_2$  diluent monitors used to determine heat input, moisture monitoring systems,  $\text{NO}_x$  concentration monitoring systems, flow monitors,  $\text{NO}_x$ -diluent monitoring systems or  $\text{SO}_2$ -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  $\text{SO}_2$  or  $\text{CO}_2$  pollutant concentration monitor (including an  $\text{O}_2$  pollutant monitor used to measure  $\text{CO}_2$  using the procedures in

appendix F to this part), or of a CO<sub>2</sub> or O<sub>2</sub> diluent monitor used to determine heat input, or of a NO<sub>x</sub> concentration monitoring system, or of a NO<sub>x</sub>-diluent monitoring system, or of an SO<sub>2</sub>-diluent continuous emissions monitoring system is  $\leq 7.5$  percent;

(b) Prior to January 1, 2000, the relative accuracy during the audit of a flow monitor is  $\leq 10.0$  percent at each operating level tested;

(c) On and after January 1, 2000, the relative accuracy during the audit of a flow monitor is  $\leq 7.5$  percent at each operating level tested;

(d) For low flow ( $\leq 10.0$  fps) stacks/ducts, when the flow monitor fails to achieve a relative accuracy  $\leq 7.5$  percent (10.0 percent if prior to January 1, 2000) 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  $\pm 1.5$  fps of the reference method mean value, converted to an equivalent velocity in fps;

(e) For low SO<sub>2</sub> or NO<sub>x</sub> emitting units (average SO<sub>2</sub> or NO<sub>x</sub> concentrations  $\leq 250$  ppm, when an SO<sub>2</sub> pollutant concentration monitor or NO<sub>x</sub> concentration monitoring system fails to achieve a relative accuracy  $\leq 7.5$  percent during the audit, but the monitor mean value from the RATA is within  $\pm 12$  ppm of the reference method mean value;

(f) For units with low NO<sub>x</sub> emission rates (average NO<sub>x</sub> emission rate  $\leq 0.200$  lb/mmBtu), when a NO<sub>x</sub>-diluent continuous emission monitoring system fails to achieve a relative accuracy  $\leq 7.5$  percent, but the monitoring system mean value from the RATA, calculated using Equation A-7 in appendix A to this part, is within  $\pm 0.015$  lb/mmBtu of the reference method mean value;

(g) For units with low SO<sub>2</sub> emission rates (average SO<sub>2</sub> emission rate  $\leq 0.500$  lb/mmBtu), when an SO<sub>2</sub>-diluent continuous emission monitoring system fails to achieve a relative accuracy  $\leq 7.5$  percent, but the monitoring system mean value from the RATA, calculated using Equation A-7 in appendix A to this part, is within  $\pm 0.025$  lb/mmBtu of the reference method mean value;

(h) For a CO<sub>2</sub> or O<sub>2</sub> monitor, when the mean difference between the reference method values from the RATA and the corresponding monitor values is within  $\pm 0.7$  percent CO<sub>2</sub> or O<sub>2</sub>; and

(i) When the relative accuracy of a continuous moisture monitoring system is  $\leq 7.5$  percent or when the mean difference between the reference method values from the RATA and the corresponding monitoring system values is within  $\pm 1.0$  percent H<sub>2</sub>O.

#### 2.3.1.3 RATA Load Levels and Additional RATA Requirements

(a) For SO<sub>2</sub> pollutant concentration monitors, CO<sub>2</sub> pollutant concentration monitors (including O<sub>2</sub> monitors used to determine

CO<sub>2</sub> emissions), CO<sub>2</sub> or O<sub>2</sub> diluent monitors used to determine heat input, NO<sub>x</sub> concentration monitoring systems, moisture monitoring systems, SO<sub>2</sub>-diluent monitoring systems and NO<sub>x</sub>-diluent monitoring systems, the required semiannual or annual RATA tests shall be done at the load level designated as normal under section 6.5.2.1 of appendix A to this part. If two load levels are designated as normal, the required RATA(s) may be done at either load level.

(b) For flow monitors installed on peaking units and bypass stacks, all required semiannual or annual relative accuracy test audits shall be single-load audits at the normal load, as defined in section 6.5.2.1 of appendix A to this part.

(c) For all other flow monitors, the RATAs shall be performed as follows:

(1) An annual 2-load flow RATA shall be done at the two most frequently used load levels, as determined under section 6.5.2.1 of appendix A to this part.

(2) If the flow monitor is on a semiannual RATA frequency, 2-load flow RATAs and single-load flow RATAs at normal load may be performed alternately.

(3) A single-load annual flow RATA, at the most frequently used load level, may be performed in lieu of the 2-load 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 7 days prior to the date of the current annual flow RATA, the unit has operated at a single load level (low, mid or high) for  $\geq 85.0$  percent of the time. \* \* \*

(4) A 3-load RATA, at the low-, mid-, and high-load levels, determined under section 6.5.2.1 of appendix A to this part, shall be performed at least once in every period of five consecutive calendar years.

(5) A 3-load RATA is required whenever a flow monitor is re-linearized, i.e., when its polynomial coefficients or K factor(s) are changed.

(6) For all multi-level flow audits, the audit points at adjacent load 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. 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 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 flow RATAs, each load 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, only the RATA at that load level must be repeated; the results of any previously-passed RATA(s) at the other load level(s) are unaffected, unless re-linearization of the monitor is required to correct the problem that caused the calibration failure, in which case a subsequent 3-load RATA is required).

(e) If a 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, 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). Note that a monitoring system shall not be considered out-of-control when a RATA is aborted for a reason other than monitoring system malfunction (see paragraph (h) of this section).

(f) For a 2-level or 3-level flow RATA, if, at any load level, a RATA is failed or aborted due to a problem with the flow monitor, the RATA at that load 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, 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) 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 RATA is required.

(g) For a CO<sub>2</sub> pollutant concentration monitor (or an O<sub>2</sub> monitor used to measure CO<sub>2</sub> emissions) which also serves as the diluent component in a NO<sub>x</sub>-diluent (or SO<sub>2</sub>-diluent) monitoring system, if the CO<sub>2</sub> (or O<sub>2</sub>) RATA is failed, then both the CO<sub>2</sub> (or O<sub>2</sub>) monitor and the associated NO<sub>x</sub>-diluent (or SO<sub>2</sub>-diluent) system are considered out-of-control, beginning with the hour of completion of the failed CO<sub>2</sub> (or O<sub>2</sub>) 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).

(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<sub>2</sub> pollutant concentration monitor, a NO<sub>x</sub>-diluent monitoring system, a NO<sub>x</sub> 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<sub>2</sub>, NO<sub>x</sub>, 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.

### 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: a required RATA has not been performed by the end of the QA operating quarter in which it is due; or five

consecutive calendar years have elapsed without a required 3-load flow RATA having been conducted; or for a unit which is conditionally exempted under § 75.21(a)(7) from the SO<sub>2</sub> RATA requirements of this part, an SO<sub>2</sub> 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 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<sub>2</sub> monitors, only), or a combination of these factors.

(b) Except for SO<sub>2</sub> 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<sub>2</sub> 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. Note that when a RATA (or RATAs, if more than one attempt is made) is done during a grace period in order to satisfy a RATA requirement from a previous quarter, the deadline for the next RATA shall be determined from the quarter in which the RATA was due, not from the quarter in which the RATA is actually completed. However, if a RATA deadline determined in this manner is less than two QA operating quarters from the quarter in which the missed RATA is completed, the RATA deadline shall be re-set at two QA operating quarters from the quarter in which the missed RATA is completed.

### 2.3.4 Bias Adjustment Factor

Except as otherwise specified in section 7.6.5 of appendix A to this part, if an SO<sub>2</sub> pollutant concentration monitor, flow monitor, NO<sub>x</sub> continuous emission monitoring system, or NO<sub>x</sub> concentration monitoring system used to calculate NO<sub>x</sub> 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 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 or a passing 2-load or 3-load 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 and 3-load flow RATAs, use the highest percentage relative accuracy at any of the loads to determine the RATA frequency. The results of a single-load flow RATA may be used to establish the RATA frequency when the single-load flow RATA is specifically required under section 2.3.1.3(b) of this appendix (for flow monitors installed on peaking units and bypass stacks) or when the single-load RATA is allowed under section 2.3.1.3(c) of this appendix for a unit that has operated at the most fre-

quently used load level for ≥85.0 percent of the time since the last annual flow RATA. No other single-load flow RATA may be used to establish an annual RATA frequency; however, a 2-load or 3-load flow RATA may be performed at any time or in place of any required single-load 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	QA test frequency requirements		
	Daily*	Quarterly*	Semiannual*
Calibration Error (2 pt.)	✓		
Interference (flow)	✓		
Flow-to-Load Ratio		✓	
Leak Check (DP flow monitors)		✓	
Linearity (3 pt.)		✓	
RATA (SO <sub>2</sub> , NO <sub>x</sub> , CO <sub>2</sub> , H <sub>2</sub> O) <sup>1</sup>			✓
RATA (flow) <sup>1,2</sup>			✓

\*For monitors on bypass stack/duct, "daily" means bypass operating days, only. "Quarterly" means once every QA operating quarter. "Semiannual" means once every two QA operating quarters.

<sup>1</sup>Conduct RATA annually (i.e., once every four QA operating quarters), if monitor meets accuracy requirements to qualify for less frequent testing.

<sup>2</sup>For flow monitors installed on peaking units and bypass stacks, conduct all RATAs at a single, normal load. For other flow monitors, conduct annual RATAs at the two load levels used most frequently since the last annual RATA. Alternating single-load and 2-load RATAs may be done if a monitor is on a semiannual frequency. A single-load RATA may be done in lieu of a 2-load RATA if, since the last annual flow RATA, the unit has operated at one load level for ≥85.0 percent of the time. A 3-load RATA is required at least once in every period of five consecutive calendar years and whenever a flow monitor is re-linearized.

FIGURE 2 TO APPENDIX B OF PART 75—RELATIVE ACCURACY TEST FREQUENCY INCENTIVE SYSTEM.

RATA	Semiannual <sup>1</sup> (percent)	Annual <sup>1</sup>
SO <sub>2</sub> or NO <sub>x</sub> <sup>3</sup>	7.5% < RA ≤ 10.0% or ± 15.0 ppm <sup>2</sup>	RA ≤ 7.5% or ± 12.0 ppm <sup>2</sup>
SO <sub>2</sub> -diluent	7.5% < RA ≤ 10.0% or ± 0.030	RA ≤ 7.5% or ± 0.025.

FIGURE 2 TO APPENDIX B OF PART 75—RELATIVE ACCURACY TEST FREQUENCY INCENTIVE SYSTEM.—Continued

RATA	Semiannual <sup>1</sup> (percent)	Annual <sup>1</sup>
NO <sub>x</sub> -diluent .....	lb/mmBtu <sup>2</sup> ..... 7.5% < RA ≤ 10.0% or ± 0.020 .....	lb/mmBtu <sup>2</sup> ..... RA ≤ 7.5% or ± 0.015.
Flow (Phase I) .....	lb/mmBtu <sup>2</sup> ..... 10.0% < RA ≤ 15.0% or ± 1.5 fps <sup>2</sup> .....	lb/mmBtu <sup>2</sup> ..... RA ≤ 10.0%.
Flow (Phase II) .....	7.5% < RA ≤ 10.0% or ± 1.5 fps <sup>2</sup> .....	RA ≤ 7.5%.
CO <sub>2</sub> or O <sub>2</sub> .....	7.5% < RA ≤ 10.0% or ± 1.0% CO <sub>2</sub> /O <sub>2</sub> <sup>2</sup> .....	RA ≤ 7.5% or ± 0.7% CO <sub>2</sub> /O <sub>2</sub> <sup>2</sup> .
Moisture .....	7.5% < RA ≤ 10.0% or ± 1.5% H <sub>2</sub> O <sup>2</sup> .....	RA ≤ 7.5% or ± 1.0% H <sub>2</sub> O <sup>2</sup> .

<sup>1</sup>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<sub>2</sub> monitors, QA operating quarters in which only very low sulfur fuel as defined in § 72.2, 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.

<sup>2</sup>The difference between monitor and reference method mean values applies to moisture monitors, CO<sub>2</sub>, and O<sub>2</sub> monitors, low emitters, or low flow, only.

<sup>3</sup>A NO<sub>x</sub> concentration monitoring system used to determine NO<sub>x</sub> mass emissions under § 75.71.

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APPENDIX C TO PART 75—MISSING DATA ESTIMATION PROCEDURES

1. PARAMETRIC MONITORING PROCEDURE FOR MISSING SO<sub>2</sub> CONCENTRATION OR NO<sub>x</sub> EMISSION RATE DATA

1.1 Applicability

The owner or operator of any affected unit equipped with post-combustion SO<sub>2</sub> or NO<sub>x</sub> emission controls and SO<sub>2</sub> pollutant concentration monitors and/or NO<sub>x</sub> 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<sub>2</sub> of postcombustion NO<sub>x</sub> emission controls which, with the monitored inlet concentration or emission rate data, may be used to estimate the average concentration of SO<sub>2</sub> emissions or average emission rate of NO<sub>x</sub> discharged to the atmosphere. After approval by the Administrator, such method or model may be used for filling in missing SO<sub>2</sub> concentration or NO<sub>x</sub> emission rate data when data from the outlet SO<sub>2</sub> pollutant concentration monitor or outlet NO<sub>x</sub> 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<sub>2</sub> or NO<sub>x</sub> removal efficiency and of the parameters specified below, at a minimum. The affected facility shall supply additional parametric information where appropriate. Measure the SO<sub>2</sub> concentration or NO<sub>x</sub> 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<sub>2</sub> 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<sub>2</sub> 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<sub>2</sub> 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<sub>x</sub> 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<sub>x</sub> emission rate as determined by the NO<sub>x</sub> 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<sub>x</sub> 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<sub>2</sub> or post-combustion NO<sub>x</sub> 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<sub>2</sub> emission controls on an hourly basis.

Each parametric data substitution procedure should develop a data correlation procedure to verify the performance of the SO<sub>2</sub> emission controls or post-combustion NO<sub>x</sub> emission controls, along with the SO<sub>2</sub> pollutant concentration monitor and NO<sub>x</sub> continuous emission monitoring system values for varying unit load ranges.

For NO<sub>x</sub> 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<sub>2</sub> pollutant concentration monitor data.

$$M_o = I_c (1-E)$$

(Eq. C-1)

where,

M<sub>o</sub> = Substitute data for outlet SO<sub>2</sub> concentration, ppm.

I<sub>c</sub> = Recorded inlet SO<sub>2</sub> concentration, ppm.

E = Removal efficiency of SO<sub>2</sub> 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<sub>x</sub> emission rate data.

$$M_o = I_c (1-E)$$

(Eq. C-2)

where,

M<sub>o</sub> = Substitute data for outlet NO<sub>x</sub> emission rate, lb/mmBtu.

I<sub>c</sub> = Recorded inlet NO<sub>x</sub> emission rate, lb/mmBtu.

E = Removal efficiency of post-combustion NO<sub>x</sub> 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<sub>2</sub> pollutant concentration monitors are unavailable simultaneously, use the maximum inlet SO<sub>2</sub> concentration recorded by the inlet SO<sub>2</sub> pollutant concentration monitor during the previous 720 quality assured monitor operating hours to substitute for the inlet SO<sub>2</sub> concentration in equation C-1 of this appendix.

1.5.2 If both the inlet and outlet NO<sub>x</sub> continuous emission monitoring systems are unavailable simultaneously, use the maximum inlet NO<sub>x</sub> emission rate for the corresponding unit load recorded by the NO<sub>x</sub> continuous emission monitoring system at the inlet during the previous 2160 quality assured monitor operating hours to substitute for the inlet NO<sub>x</sub> 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<sub>2</sub> concentration or NO<sub>x</sub> 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 AND NO<sub>x</sub> 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<sub>x</sub> emission rate (in lb/mmBtu) from NO<sub>x</sub>-diluent continuous emission monitoring systems, and NO<sub>x</sub> concentration data (in ppm) from NO<sub>x</sub> concentration monitoring systems used to determine NO<sub>x</sub> 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<sub>x</sub>) 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

TABLE C-1.—DEFINITION OF OPERATING LOAD RANGES FOR LOAD-BASED SUBSTITUTION DATA PROCEDURES—Continued

Operating load range	Percent of maximum hourly gross load or maximum hourly gross steam load (percent)
10 .....	≤90

2.2.2 Beginning with the first hour of unit operation after installation and certification of the flow monitor or the NO<sub>x</sub>-diluent continuous emission monitoring system (or a NO<sub>x</sub> concentration monitoring system used to determine NO<sub>x</sub> 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<sub>x</sub>-diluent continuous emission monitoring system (or a NO<sub>x</sub> concentration monitoring system used to determine NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> emission rate, in lb/mmBtu, reported by a NO<sub>x</sub> continuous emission monitoring system.

2.2.3.6 The 90th percentile value of hourly NO<sub>x</sub> emission rates, in lb/mmBtu.

2.2.3.7 The 95th percentile value of hourly NO<sub>x</sub> emission rates, in lb/mmBtu.

2.2.3.8 The maximum value of hourly NO<sub>x</sub> emission rates, in lb/mmBtu.

2.2.3.9 Average of the hourly NO<sub>x</sub> pollutant concentrations, in ppm, reported by a NO<sub>x</sub> concentration monitoring system used to determine NO<sub>x</sub> mass emissions, as defined in §75.71(a)(2).

2.2.3.10 The 90th percentile value of hourly NO<sub>x</sub> pollutant concentration, in ppm.

2.2.3.11 The 95th percentile value of hourly NO<sub>x</sub> pollutant concentration, in ppm.

2.2.3.12 The maximum value of hourly NO<sub>x</sub> 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<sub>x</sub>-diluent continuous emission monitoring system (and/or the NO<sub>x</sub> concentration monitoring system used to determine NO<sub>x</sub> 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<sub>x</sub> emission rate data (and where applicable, NO<sub>x</sub> 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]

#### APPENDIX D TO PART 75—OPTIONAL SO<sub>2</sub> EMISSIONS DATA PROTOCOL FOR GAS-FIRED AND OIL-FIRED UNITS

##### 1. APPLICABILITY

1.1 This protocol may be used in lieu of continuous SO<sub>2</sub> pollutant concentration and flow monitors for the purpose of determining hourly SO<sub>2</sub> 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<sub>2</sub> 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. Whenever the monitoring method is to be changed, reapply to the Administrator for recertification of the new monitoring method.

## 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 (i.e., a pipe carrying fuel for multiple units). 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 are not applicable to any unit that is using the provisions of subpart H of this part to monitor, record, and report NO<sub>x</sub> mass emissions under a state or federal NO<sub>x</sub> mass emission reduction program. For all other units, if the fuel flowmeter is installed in a common pipe header, do one of the following:

2.1.2.1 Measure the fuel flow rate in the common pipe, and combine SO<sub>2</sub> mass emissions for the affected units for recordkeeping and compliance purposes; or

2.1.2.2 Provide information satisfactory to the Administrator on methods for apportioning SO<sub>2</sub> mass emissions and heat input to each of the affected units demonstrating that the method ensures complete and accurate accounting of the actual emissions from each of the affected units included in the apportionment and all emissions regulated under this part. The information shall be provided to the Administrator through a petition submitted by the designated representative under §75.66. Satisfactory information includes: the proposed apportionment, using fuel flow measurements; the ratio of hourly integrated gross load (in MWe-hr) in each unit to the total load for all units receiving fuel from the common pipe header, or the ratio of hourly steam flow (in 1000 lb) at each unit to the total steam flow for all units receiving fuel from the common pipe header (see section 3.4.3 of this appendix); and documentation that shows the provisions of sections 2.1.5 and 2.1.6 of this appendix have been met for the fuel flowmeter used in the apportionment.

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 or a gas-fired unit that uses oil solely for start-up or burner ignition, a flowmeter for the start-up fuel is 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. Additionally, begin sampling the emergency fuel for sulfur content only using the procedures under section 2.2 (for oil) or 2.3 (for gas) of this appendix. The designated representative shall also provide notice under §75.61(a)(6)(ii) 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 calibrated fuel flow rate) 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 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 measurement against a NIST traceable reference method.

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-1989 with September 1990 Errata ("Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi"); ASME MFC-4M-1986 (Reaffirmed 1990), "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 ("Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters"); ASME MFC-6M-1987 with June 1987 Errata ("Measurement of Fluid Flow in Pipes Using Vortex Flow Meters"); 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) Section 2, "Conventional Pipe Provers", Section 3, "Small Volume Provers", and Section 5, "Master-Meter Provers", from Chapter 4 of the Manual of Petroleum Measurement Standards, October 1988 (Reaffirmed 1993); or ASME MFC-9M-1988 with December 1989 Errata ("Measurement of Liquid Flow in Closed Conduits by Weighing Method"), for all other flowmeter types (incorporated by reference under § 75.6). 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 proce-

dures 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:

$$ACC = \frac{|R - A|}{URV} \times 100 \quad (\text{Eq. D-1})$$

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 using the following Table D-1.

TABLE D-1.—TABLE OF FLOWMETER ACCURACY RESULTS

Test number: \_\_\_\_\_ Test completion date<sup>1</sup>: \_\_\_\_\_ Test completion time<sup>1</sup>: \_\_\_\_\_  
 Reinstallation date<sup>2</sup> (for testing under 2.1.5.1 only): \_\_\_\_\_ Reinstallation time<sup>2</sup>: \_\_\_\_\_  
 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 _____ percent <sup>3</sup> of URV	1	.....	.....	.....	.....
	2	.....	.....	.....	.....
	3	.....	.....	.....	.....
	Average	.....	.....	.....	.....
Mid-level _____ percent <sup>3</sup> of URV	1	.....	.....	.....	.....
	2	.....	.....	.....	.....
	3	.....	.....	.....	.....
	Average	.....	.....	.....	.....
High (Maximum) level _____ percent <sup>3</sup> of URV	1	.....	.....	.....	.....
	2	.....	.....	.....	.....
	3	.....	.....	.....	.....
	Average	.....	.....	.....	.....

<sup>1</sup> Report the date, hour, and minute that all test runs were completed.  
<sup>2</sup> For laboratory tests not performed inline, report the date and hour that the fuel flowmeter was reinstalled following the test.  
<sup>3</sup> 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 2.1.5.1 or 2.1.5.2 of this appendix or perform a transmitter accuracy test once every four fuel flowmeter QA operating quarters and a primary element visual inspection once every 12 calendar quarters, 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 transmitter accuracy test and primary element inspection, where applicable, 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 transmitter accuracy test and primary element inspection, where applicable.

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 levels (e.g., “mid” and “high”), such that the full range of transmitter or transducer readings corresponding to normal unit operation is represented.

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(b) Calculate the accuracy of each transmitter or transducer at each level tested, using the following equation:

$$ACC = \frac{|R - T|}{FS} \times 100 \quad (\text{Eq. D-1a})$$

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 and Reporting of 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. When testing individual orifice, nozzle, or venturi meter transmitters or transducers for accuracy, include the information displayed in the following Table D-2. At a minimum, record results for each transmitter or transducer at the zero-level and at least two other levels across the range of the transmitter or transducer readings that correspond to normal unit operation.

**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:<sup>3</sup> \_\_\_\_\_  
 Transducer/Transmitter Type (check one):  
 Differential Pressure  
 Static Pressure  
 Temperature

Measurement level (percent of full-scale)	Run number (if multiple runs) <sup>2</sup>	Run time (HHMM)	Transmitter/transducer input (pre-calibration)	Expected transmitter/transducer output (reference)	Actual transmitter/transducer output <sup>3</sup>	Percent accuracy (percent of full-scale)
Low (Minimum) level _____ percent <sup>1</sup> of full-scale	.....					
Mid-level _____ percent <sup>1</sup> of full-scale (If tested at more than 3 levels)	.....					
2nd Mid-level _____ percent <sup>1</sup> of full-scale (If tested at more than 3 levels)	.....					
3rd Mid-level _____ percent <sup>1</sup> of full-scale	.....					
High (Maximum) level _____ percent <sup>1</sup> of full-scale	.....					

<sup>1</sup> 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.  
<sup>2</sup> It is required to test at least once at each level.  
<sup>3</sup> Use the same units of measure for all readings (e.g., use degrees (°), inches of water (in H<sub>2</sub>O), pounds per square inch (psi), or milliamperes (ma) for both transmitter or transducer readings and reference readings).

(b) 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 flowmeter accuracy results for the fuel flowmeter at the three flow rate levels specified in section 2.1.5.2 of this appendix.

(c) 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.

#### 2.1.6.3 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 § 75.56 or § 75.59, as applicable.

#### 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 inspec-

tion may be performed using a baroscope. If the visual inspection indicates that 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);

(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 under 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) If the primary element size is changed, calibrate the transmitter or transducers consistent with the new primary element size. 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);

(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 under 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 this period, 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 flowmeter transmitter test and primary element inspection, where applicable, 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 a transmitter accuracy test and a primary element inspection, where applicable, are conducted. Notwithstanding the requirements of §75.54(a) or §75.57(a), as applicable, 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  $R_{\text{base}}$ , 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 (i.e., 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 of both the most recent transmitter or transducer test and the most recent primary element inspection for that fuel flowmeter. From these 168 (or more) hours of baseline data, calculate the baseline fuel flow rate-to-load ratio as follows:

$$R_{\text{base}} = \frac{Q_{\text{base}}}{L_{\text{avg}}} \quad (\text{Eq. D-1b})$$

where:

$R_{\text{base}}$  = Value of the fuel flow rate-to-load ratio during the baseline period; 100 scfh/MWe or 100 scfh/klb per hour steam load for gas-firing; (lb/hr)/MWe or (lb/hr)/klb per hour steam load for oil-firing.

$Q_{\text{base}}$  = Average fuel flow rate measured by the fuel flowmeter during the baseline period, 100 scfh for gas-firing and lb/hr for oil-firing.

$L_{\text{avg}}$  = Average unit load during the baseline period, megawatts or 1000 lb/hr of steam.

(b) In Equation D-1b, for a common pipe header,  $L_{\text{avg}}$  is the sum of the operating loads of all units that receive fuel through the common pipe header. For a unit that receives its fuel through multiple pipes,  $Q_{\text{base}}$  is the sum of the fuel flow rates for a particular fuel (i.e., gas, diesel fuel, or residual oil) from each of the pipes. Round off the value of  $R_{\text{base}}$  to the nearest tenth.

(c) Alternatively, a baseline value of the gross heat rate (GHR) may be determined in lieu of  $R_{\text{base}}$ . The baseline value of the GHR,  $GHR_{\text{base}}$ , shall be determined as follows:

$$(\text{GHR})_{\text{base}} = \frac{(\text{Heat Input})_{\text{avg}}}{L_{\text{avg}}} \times 1000 \quad (\text{Eq. D-1c})$$

Where:

$(\text{GHR})_{\text{base}}$  = Baseline value of the gross heat rate during the baseline period, Btu/kwh or Btu/lb steam load.

$(\text{Heat Input})_{\text{avg}}$  = Average (mean) hourly heat input rate recorded by the fuel flowmeter during the baseline period, as determined using the applicable equation in appendix F to this part, mmBtu/hr.

$L_{\text{avg}}$  = Average (mean) unit load during the baseline period, megawatts or 1000 lb/hr of steam.

(d) Report the current value of  $R_{\text{base}}$  (or  $\text{GHR}_{\text{base}}$ ) and the completion date of the associated quality assurance procedure in each electronic quarterly report required under §75.64.

#### 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  $R_{\text{h}}$ , the hourly fuel flow-to-load ratio, for every quality assured hourly average fuel flow rate obtained with a certified fuel flowmeter.

$$R_{\text{h}} = \frac{Q_{\text{h}}}{L_{\text{h}}} \quad (\text{Eq. D-1d})$$

where:

$R_{\text{h}}$  = Hourly value of the fuel flow rate-to-load ratio; 100 scfh/MWe, (lb/hr)/MWe, 100 scfh/1000 lb/hr of steam load, or (lb/hr)/1000 lb/hr of steam load.

$Q_{\text{h}}$  = Hourly fuel flow rate, as measured by the fuel flowmeter, 100 scfh for gas-firing or lb/hr for oil-firing.

$L_{\text{h}}$  = Hourly unit load, megawatts or 1000 lb/hr of steam.

(b) For a common pipe header,  $L_{\text{h}}$  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 its fuel through multiple pipes,  $Q_{\text{h}}$  will be the sum of the fuel flow rates for a particular fuel (i.e., gas, diesel fuel, or residual oil) from each of the pipes. Round off each value of  $R_{\text{h}}$  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:

$$(\text{GHR})_{\text{h}} = \frac{(\text{Heat Input})_{\text{h}}}{L_{\text{h}}} \times 1000 \quad (\text{Eq. D-1e})$$

Where:

$(\text{GHR})_{\text{h}}$  = Hourly value of the gross heat rate, Btu/kwh or Btu/lb steam load.

$(\text{Heat Input})_{\text{h}}$  = Hourly heat input rate, as determined using the applicable equation in appendix F to this part, mmBtu/hr.

$L_{\text{h}}$  = Hourly unit load, megawatts or 1000 lb/hr of steam.

(d) Evaluate the calculated flow rate-to-load ratios (or gross heat rates) as follows. Perform a separate data analysis for each fuel flowmeter following the procedures of this section. Base each analysis on a minimum of 168 hours of data. If, for a particular fuel flowmeter, fewer than 168 hourly flow-to-load ratios (or GHR values) are available, a flow-to-load (or GHR) evaluation is not required for that flowmeter for that calendar quarter.

(e) For each hourly flow-to-load ratio or GHR value, calculate the percentage dif-

ference (percent  $D_{\text{h}}$ ) from the baseline fuel flow-to-load ratio using Equation D-1f.

$$\%D_{\text{h}} = \frac{|R_{\text{base}} - R_{\text{h}}|}{R_{\text{base}}} \times 100 \quad (\text{Eq. D-1f})$$

Where:

$\%D_{\text{h}}$  = 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).

$R_{\text{h}}$  = The hourly fuel flow rate-to-load ratio (or GHR).

$R_{\text{base}}$  = 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  $R_{\text{base}}$  and  $R_{\text{h}}$  in Equation D-1f if the fuel flow-to-load ratio is being evaluated, and consistently use

(GHR)<sub>base</sub> and (GHR)<sub>h</sub> 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<sub>h</sub>) values using Equation D-1g, as follows:

$$E_f = \sum_{h=1}^q \frac{\%D_h}{q} \quad (\text{Eq. D-1g})$$

Where:

E<sub>f</sub> = 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<sub>h</sub> = 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<sub>f</sub>) 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<sub>f</sub> is no greater than 15.0 percent.

2.1.7.3 Optional Data Exclusions

(a) If E<sub>f</sub> is outside the limits in section 2.1.7.2 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 identify and exclude fuel flow-to-load ratios or GHR values for any non-representative fuel flow-to-load ratios or GHR values. Specifically, the R<sub>h</sub> or (GHR)<sub>h</sub> values for the following hours may be considered non-representative: any hour in which the unit combusted another fuel in addition to the fuel measured by the fuel flowmeter being tested; or 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 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.

2.1.7.4 Consequences of Failed Fuel Flow-to-Load Ratio Test

(a) If E<sub>f</sub> is outside the applicable limit in section 2.1.7.2 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<sub>f</sub> 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<sub>f</sub> 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<sub>base</sub> or (GHR)<sub>base</sub> shall be established no later than two flowmeter QA operating quarters 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<sub>base</sub> or (GHR)<sub>base</sub> 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 fuel 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: \_\_\_\_\_

TABLE D-3.—BASELINE INFORMATION AND TEST RESULTS FOR FUEL FLOW-TO-LOAD TEST—  
Continued

Unit/pipe ID #: _____ Fuel flowmeter component and system ID #s: _____ - _____ Calendar quarter (1st, 2nd, 3rd, 4th) and year: _____	
Range of operation: _____ to _____ MWe or klb steam/hr (indicate units)	
Time period	
Baseline period	Quarter
Completion date and time of most recent primary element inspection (orifice-, nozzle-, and venturi-type flowmeters only). ____/____/____:____	Number of hours excluded from quarterly average due to co-firing different fuels: _____ hrs.
Completion date and time of the most recent flowmeter or transmitter accuracy test ____/____/____:____	Number of hours excluded from quarterly average due to ramping load: _____ hrs.
Beginning 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.
End date and time of baseline period .....	Number of hours included in quarterly average: _____ hrs.
Average fuel flow rate _____ (100 scfh for gas and lb/hr for oil) .....	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.	

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<sub>2</sub> 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
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; or 3. Maximum value allowed by contract. <sup>1</sup>
	As delivered (in delivery truck or barge). <sup>1</sup> ....	1. Highest of all sampled values in previous calendar year; or 2. Maximum value allowed by contract. <sup>1</sup>
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.

TABLE D-4—OIL SAMPLING METHODS AND SULFUR, DENSITY AND GROSS CALORIFIC VALUE USED IN CALCULATIONS—Continued

Parameter	Sampling technique/frequency	Value used in calculations
	In storage tank (after addition of fuel to tank)	1. Actual measured value; or 2. Highest of all sampled values in previous calendar year; or 3. Maximum value allowed by contract. <sup>1</sup>
	As delivered (in delivery truck or barge). <sup>1</sup> ....	1. Highest of all sampled values in previous calendar year; or 2. Maximum value allowed by contract. <sup>1</sup>
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; or 3. Maximum value allowed by contract. <sup>1</sup>
	As delivered (in delivery truck or barge). <sup>1</sup> ....	1. Highest of all sampled values in previous calendar year; or 2. Maximum value allowed by contract. <sup>1</sup>

<sup>1</sup> 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.

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 D4177-82 (Reapproved 1990), "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<sub>2</sub> 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 D4057-88, "Standard Practice for Manual Sampling of Petroleum and Petroleum Products" (incorporated by reference under §75.6). 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<sub>2</sub> 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 D4057-88, "Standard Practice for Manual Sampling of Petroleum and Petroleum Products" (incorporated by reference under §75.6). Use the

sulfur content (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 of this appendix to calculate SO<sub>2</sub> 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 of this appendix.

#### 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 D4057-88, "Standard Practice for Manual Sampling of Petroleum and Petroleum Products" (incorporated by reference under §75.6). Except as otherwise provided in this section, calculate SO<sub>2</sub> mass emission rate using the sulfur content (and where required, the density) from one of the two following values, and calculate heat input using the gross calorific value from one of the two following 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) 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 use the actual sampled value for sulfur content, gross calorific value, or density of fuel to calculate SO<sub>2</sub> mass emission rate or heat input rate as the new assumed sulfur content, gross calorific value, or density. Continue to use this new assumed value to calculate SO<sub>2</sub> mass emis-

sion rate or heat input rate unless and until: it is superseded by a higher value from an oil sample; or 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 Split and label each oil sample. Maintain a portion (at least 200 cc) of each sample 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. Analyze oil samples for percent sulfur content by weight in accordance with ASTM D129-91, "Standard Test Method for Sulfur in Petroleum Products (General Bomb Method)," ASTM D1552-90, "Standard Test Method for Sulfur in Petroleum Products (High Temperature Method)," ASTM D2622-92, "Standard Test Method for Sulfur in Petroleum Products by X-Ray Spectrometry," or ASTM D4294-90, "Standard Test Method for Sulfur in Petroleum Products by Energy-Dispersive X-Ray Fluorescence Spectroscopy" (incorporated by reference under §75.6).

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 D287-82 (Reapproved 1991), "Standard Test Method for API Gravity of Crude Petroleum and Petroleum Products (Hydrometer Method)," ASTM D941-88, "Standard Test Method for Density and Relative Density (Specific Gravity) of Liquids by Lipkin Bicapillary Pycnometer," ASTM D1217-91, "Standard Test Method for Density and Relative Density (Specific Gravity) of Liquids by Bingham Pycnometer," ASTM D1481-91, "Standard Test Method for Density and Relative Density (Specific Gravity) of Viscous Materials by Lipkin Bicapillary," ASTM D1480-91, "Standard Test Method for Density and Relative Density (Specific Gravity) of Viscous Materials by Bingham Pycnometer," ASTM D1298-85 (Reapproved 1990), "Standard Practice for Density, Relative Density (Specific Gravity) or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method," or ASTM D4052-91, "Standard Test Method for Density and Relative Density of Liquids by Digital Density Meter" (incorporated by reference under §75.6).

2.2.7 Analyze oil samples to determine the heat content of the fuel. Determine oil heat content in accordance with ASTM D240-87 (Reapproved 1991), "Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter," ASTM D2382-88, "Standard Test Method for Heat or Combustion of Hydrocarbon Fuels by Bomb

Calorimeter (High-Precision Method)", or ASTM D2015-91, "Standard Test Method for Gross Calorific Value of Coal and Coke by the Adiabatic Bomb Calorimeter" (incorporated by reference under §75.6) or any other procedures listed in section 5.5 of appendix F of this part.

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<sub>2</sub> Emissions From Combustion of Gaseous Fuels

(a) Account for the hourly SO<sub>2</sub> 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<sub>2</sub> 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<sub>2</sub> 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<sub>2</sub> 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
Gas Sulfur Content.	Pipeline Natural Gas with H <sub>2</sub> S content less than or equal to 0.3 grains/100scf when using the provisions of section 2.3.1 to determine SO <sub>2</sub> mass emissions.	0.0006 lb/mmBtu.
	Natural Gas with H <sub>2</sub> S content less than or equal to 1.0 grain/100scf when using the provisions of section 2.3.2 to determine SO <sub>2</sub> mass emissions.	Default SO <sub>2</sub> emission rate calculated from Eq. D-1h, using either the fuel contract maximum H <sub>2</sub> S or the maximum H <sub>2</sub> S from historical sampling data.
	Any gaseous fuel delivered in shipments or lots—Sample each lot or shipment.	Actual % sulfur from most recent shipment or 1. Highest % sulfur from previous year's samples <sup>1</sup> ; or 2. Maximum % sulfur value allowed by contract <sup>1</sup> .
	Any gaseous fuel transmitted by pipeline and having a demonstrated "low sulfur variability" using the provisions of section 2.3.6—Sample daily.	Actual % sulfur from daily sample; or Highest % sulfur from previous 30 daily samples.
	Any gaseous fuel—Sample hourly .....	Actual hourly sulfur content of the gas.
Gas GCV ...	Pipeline Natural Gas—Sample monthly .....	1. GCV from most recent monthly sample (with ≥ 48 operating hours in the month); or 2. Maximum GCV from contract <sup>1</sup> ; or 3. Highest GCV from previous year's samples. <sup>1</sup>
	Natural Gas—Sample monthly .....	1. GCV from most recent monthly sample (with ≥ 48 operating hours in the month); or 2. Maximum GCV from contract <sup>1</sup> ; or 3. Highest GCV from previous year's samples. <sup>1</sup>
	Any gaseous fuel delivered in shipments or lots—Sample each lot or shipment.	Actual GCV from most recent shipment or lot or 1. Highest GCV from previous year's samples <sup>1</sup> ; or 2. Maximum GCV value allowed by contract. <sup>1</sup>
	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. <sup>1</sup>
	Any other gaseous fuel not having a "low GCV variability"—Sample at least daily. (Note that the use of an on-line GCV calorimeter or gas chromatograph is allowed).	Actual daily or hourly GCV of the gas.

<sup>1</sup> 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<sub>2</sub> emissions or heat input.

### 2.3.1 Pipeline Natural Gas Combustion

The owner or operator may determine the SO<sub>2</sub> 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<sub>2</sub> 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<sub>2</sub> mass emissions using either a default SO<sub>2</sub> 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<sub>2</sub> Hourly Mass Emission Rate and Hourly Mass Emissions

For pipeline natural gas combustion, calculate the SO<sub>2</sub> mass emission rate, in lb/hr, using Equation D-5 in section 3.3.2 of this appendix (when the default SO<sub>2</sub> emission rate is used). Then, use the calculated SO<sub>2</sub> mass emission rate and the unit operating time to determine the hourly SO<sub>2</sub> 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) For pipeline natural gas, provide information 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 has a hydrogen sulfide content of less than 0.3 grain/100scf. The demonstration must be made using one of the following sources of information:

- (1) The gas quality characteristics specified by a purchase contract or by a pipeline transportation contract;
- (2) A certification of the gas vendor, based on routine vendor sampling and analysis (minimum of one year of data with samples taken monthly or more frequently);
- (3) At least one year's worth of analytical data on the fuel hydrogen sulfide content

from samples taken monthly or more frequently;

(4) For fuels delivered in shipments or lots, the sulfur content from all shipments or lots received in a one year period; or

(5) Data from a 720-hour demonstration conducted using the procedures of section 2.3.6 of this appendix.

(b) When a 720-hour test is used for initial qualification as pipeline natural gas, the owner or operator is required to continue sampling the fuel for hydrogen sulfide at least once per month for one year after the initial qualification period. The use of the default natural gas SO<sub>2</sub> emission rate under 2.3.1.1 is not allowed if any sample during the one year period has a hydrogen sulfide content greater than 0.3 gr/100 scf.

### 2.3.2 Natural Gas Combustion

The owner or operator may determine the SO<sub>2</sub> 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<sub>2</sub> Emission Rate

The owner or operator may account for SO<sub>2</sub> emissions either by using a default SO<sub>2</sub> 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<sub>2</sub> 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, an SO<sub>2</sub> default emission rate may be determined using Equation D-1h. Round off the calculated SO<sub>2</sub> default emission rate to the nearest 0.0001 lb/mmBtu.

$$ER = H_2S \times 0.0026 \quad (\text{Eq. D-1h})$$

Where:

ER = Default SO<sub>2</sub> emission rate for natural gas combustion, lb/mmBtu.

H<sub>2</sub>S = Hydrogen sulfide content of the natural gas, gr/100scf.

2.3.2.1.2 The hydrogen sulfide value used in Equation D-1h may be obtained from one of the following sources of information:

- (a) The highest hydrogen sulfide content specified by a purchase contract or by a pipeline transportation contract;
- (b) The highest hydrogen sulfide content from a certification of the gas vendor, based on routine vendor sampling and analysis (minimum of one year of data with samples taken monthly or more frequently);
- (c) The highest hydrogen sulfide content from at least one year's worth of analytical data on the fuel hydrogen sulfide content

from samples taken monthly or more frequently;

(d) For fuels delivered in shipments or lots, the highest hydrogen sulfide content from all shipments or lots received in a one year period; or

(e) the highest hydrogen sulfide content measured during a 720-hour demonstration conducted using the procedures of section 2.3.6 of this appendix.

#### 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<sub>2</sub> Mass Emission Rate and Hourly Mass Emissions

For natural gas combustion, calculate the SO<sub>2</sub> mass emission rate, in lb/hr, using Equation D-5 in section 3.3.2 of this appendix, when the default SO<sub>2</sub> emission rate is used. Then, use the calculated SO<sub>2</sub> mass emission rate and the unit operating time to determine the hourly SO<sub>2</sub> 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) For natural gas, provide information 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 has a hydrogen sulfide content of less than 1.0 grain/100 scf. This demonstration must be made using one of the following sources of information:

(1) The gas quality characteristics specified by a purchase contract or by a transportation contract;

(2) A certification of the gas vendor, based on routine vendor sampling and analysis (minimum of one year of data with samples taken monthly or more frequently);

(3) At least one year's worth of analytical data on the fuel hydrogen sulfide content from samples taken monthly or more frequently;

(4) For fuels delivered in shipments or lots, sulfur content from all shipments or lots received in a one year period; or

(5) Data from a 720-hour demonstration conducted using the procedures of section 2.3.6 of this appendix.

(b) When a 720-hour test is used for initial qualification as natural gas, the owner or operator shall continue sampling the fuel for hydrogen sulfide at least once per month for one year after the initial qualification period. The use of the default natural gas SO<sub>2</sub>

emission rate under 2.3.2.1.1 is not allowed if any sample during the one year period has a hydrogen sulfide content greater than 1.0 grain/100 scf.

#### 2.3.3 SO<sub>2</sub> Mass Emissions From Any Gaseous Fuel

The owner or operator of a unit may determine SO<sub>2</sub> 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 grain/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, if a demonstration is provided under section 2.3.6 of this appendix showing that the gaseous fuel has a "low sulfur variability," determine the sulfur content daily using either manual sampling or a gas chromatograph; and for all other gaseous fuels, determine the sulfur content on an hourly basis using a gas chromatograph.

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 D1072-90, "Standard Test Method for Total Sulfur in Fuel Gases", ASTM D4468-85 (Reapproved 1989) "Standard Test Method for Total Sulfur in Gaseous Fuels by Hydrogenolysis and Radiometric Colorimetry," ASTM D5504-94 "Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence," or ASTM D3246-81 (Reapproved 1987) "Standard Test Method for Sulfur in Petroleum Gas By Oxidative Microcoulometry" (incorporated by reference under §75.6).

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<sub>2</sub> Mass Emission Rate

Calculate the SO<sub>2</sub> mass emission rate for the gaseous fuel, in lb/hr, using equation D-4 in section 3.3.1 of this appendix. Use the appropriate sulfur content, in equation D-4, as specified in Table D-5 of this appendix. That is, for fuels delivered by pipeline which demonstrate a low sulfur variability (under section 2.3.6 of this appendix) use either the daily value or the highest value in the previous 30 days or for fuels requiring hourly sulfur content sampling with a gas chromatograph use the actual hourly sulfur content).

#### 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 D1826-88, ASTM D3588-91, ASTM D4891-89, GPA Standard 2172-86 "Calculation of Gross Heating Value, Relative Density and Compressibility Factor for Natural Gas Mixtures from Compositional Analysis," or GPA Standard 2261-90 "Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography" (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.

##### 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.

##### 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 de-

scribed 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.

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 or the highest GCV in the previous year.

2.3.4.3.2 For any gaseous fuel that does not qualify as pipeline natural gas or natural gas and which is not delivered in shipments or lots which performs the required 720 hour test under section 2.3.5 of this appendix, and the results of the test demonstrate that the gaseous fuel has a low GCV variability, determine the GCV at least monthly. In calculations of hourly heat input for a unit, use either the most recent monthly sample 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 demonstration is required of 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 shall be used to determine whether daily or monthly sampling of the GCV of the gaseous fuel or blend is required.

(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 is required for any fuel which does not qualify as pipeline natural gas or natural gas and is not delivered in shipments or lots. The results of the demonstration will be used to determine whether daily or hourly sampling for sulfur in the fuel is required. To make this demonstration, proceed as follows. Provide a minimum of 720 hours of data, indicating the total sulfur content (and hydrogen sulfide content, if needed to define a fuel as either pipeline natural gas or natural gas) of the gaseous fuel or blend (in gr/100 scf). The demonstration data shall be obtained using either manual hourly sampling or an on-line gas chromatograph capable of determining fuel total sulfur content (and, if applicable, H<sub>2</sub>S content) on an hourly basis. For gaseous fuel produced by a variable process, additional data shall be provided which is representative of all process operating conditions including seasonal or annual variations which may affect fuel sulfur content.

(b) Reduce the data to hourly averages of the total sulfur content (and hydrogen sulfide content, if applicable) of the fuel. Then, calculate the mean value of the total sulfur

content and standard deviation in order to determine whether daily sampling of the sulfur content of the gaseous fuel or blend is sufficient or whether hourly sampling with a gas chromatograph is required. Specifically, daily gas sampling and analysis for total sulfur content, using either manual sampling or an online gas chromatograph, shall be sufficient, provided that the standard deviation of the hourly average values from the mean value does not exceed 5.0 grains per 100 scf. If the gaseous fuel or blend does not meet this requirement, then hourly sampling of the fuel with a gas chromatograph and hourly reporting of the average sulfur content of the fuel is required.

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, 2.3.3.1.2, 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. Irrespective of which reporting option is selected (i.e., actual value, contract value or highest value from the previous year, 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. 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 Sulfur Content .....	0.3 gr/100 scf for pipeline natural gas, or 1.0 gr/100 scf for natural gas, or Twice the highest total sulfur content value recorded in the previous 30 days when sampling gaseous fuel daily or hourly.
Gas GCV/Heat Content .....	1100 Btu/scf for pipeline natural gas, natural gas or landfill gas, or 1500 for butane or refinery gas. 2100 Btu/scf for propane or any other gaseous fuel.

2.4.2 Whenever data are missing from any fuel flowmeter that is part of an excepted monitoring system under appendix D or E to this part, where the fuel flowmeter data are required to determine the amount of fuel combusted by the unit, 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. In addition, a fuel flowmeter used for measuring fuel combusted by a peaking unit may use the simplified fuel flow missing data procedure in section 2.4.2.1 of this appendix.

#### 2.4.2.1 Simplified Fuel Flow Missing Data 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 flowmeter can measure (i.e., upper range value of flowmeter leading to a unit).

2.4.2.2 For hours where only one fuel is combusted, substitute for each hour in the missing data period the average of the hourly fuel flow rate(s) measured and recorded by the fuel flowmeter (or flowmeters, where fuel is recirculated) at the corresponding operating unit load range recorded for each missing hour during the previous 720 hours during which the unit combusted that same fuel only. Establish load ranges for the unit using the procedures of section 2 in appendix C of this part for missing volumetric flow rate data. If no fuel flow rate data are available at the corresponding load range, use data from the next higher load range where data are available. If no fuel flow rate data are available at either the corresponding load range or a higher load range during any hour of the missing data period for that fuel, substitute the maximum potential fuel flow rate. The maximum potential fuel flow rate is the lesser of the following: (1) the maximum fuel flow rate the unit is capable of

combusting or (2) the maximum flow rate that the flowmeter can measure.

2.4.2.3 For hours where two or more fuels are combusted, substitute the maximum hourly fuel flow rate measured and recorded by the flowmeter (or flowmeters, where fuel is recirculated) for the fuel for which data are missing at the corresponding load range recorded for each missing hour during the previous 720 hours when the unit combusted that fuel with any other fuel. For hours where no previous recorded fuel flow rate data are available for that fuel during the missing data period, calculate and substitute the maximum potential flow rate of that fuel for the unit as defined in section 2.4.2.2 of this appendix.

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.

### 3. Calculations

Calculate hourly SO<sub>2</sub> mass emission rate from combustion of oil fuel using the procedures in section 3.1 of this appendix. Calculate hourly SO<sub>2</sub> mass emission rate from combustion of gaseous fuel using the procedures in section 3.3 of this appendix. (Note: the SO<sub>2</sub> 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<sub>2</sub> 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<sub>2</sub> 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<sub>2</sub> Mass Emission Rate Calculation for Oil

3.1.1 Use Equation D-2 to calculate SO<sub>2</sub> mass emission rate per hour (lb/hr):

$$SO_{2\text{rate-oil}} = 2.0 \times OIL_{\text{rate}} \times \frac{\%S_{\text{oil}}}{100.0} \quad (\text{Eq. D-2})$$

Where:

SO<sub>2rate-oil</sub> = Hourly mass emission rate of SO<sub>2</sub> emitted from combustion of oil, lb/hr.

OIL<sub>rate</sub> = Mass rate of oil consumed per hr during combustion, lb/hr.

%S<sub>oil</sub> = Percentage of sulfur by weight measured in the sample.

2.0 = Ratio of lb SO<sub>2</sub>/lb S.

3.1.2 Record the SO<sub>2</sub> mass emission rate from oil for each hour that oil is combusted.

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### 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 D1250-80 (Reapproved 1990), "Standard Guide for 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):

$$OIL_{rate} = V_{oil-rate} \times D_{oil} \quad (\text{Eq. D-3})$$

$$SO2_{rate-gas} = \left( \frac{2}{7000} \right) \times GAS_{rate} \times S_{gas} \quad (\text{Eq. D-4})$$

Where:

$SO2_{rate-gas}$  = Hourly mass rate of  $SO_2$  emitted due to combustion of gaseous fuel, lb/hr.

$GAS_{rate}$  = Hourly metered flow rate of gaseous fuel combusted, 100 scf/hr.

$S_{gas}$  = 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:

$$SO2_{rate} = ER \times HI_{rate} \quad (\text{Eq. D-5})$$

where:

$SO2_{rate}$  = 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.

$$HI_{rate-gas} = \frac{GAS_{rate} \times GCV_{gas}}{10^6} \quad (\text{Eq. D-6})$$

Where:

$HI_{rate-gas}$  = Hourly heat input rate from combustion of the gaseous fuel, mmBtu/hr.

Where:

$OIL_{rate}$  = Mass rate of oil consumed per hr, lb/hr.

$V_{oil-rate}$  = 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:

$HI_{rate}$  = 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.

$GAS_{rate}$  = Average volumetric flow rate of fuel, for the portion of the hour in which the unit operated, 100 scf/hr.

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$GCV_{gas}$  = Gross calorific value of gaseous fuel, Btu/hr.

$10^6$  = Conversion of Btu to mmBtu.

(c) Note that when fuel flow is measured on an hourly totalized basis (e.g. a fuel flow-meter 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:

$$GAS_{rate} = \frac{GAS_{unit}}{t} \quad (\text{Eq. D-7})$$

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 flow-meter, 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:

$$HI_{rate-oil} = OIL_{rate} \frac{GCV_{oil}}{10^6} \quad (\text{Eq. D-8})$$

Where:

$HI_{rate-oil}$  = 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, 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 flow-meter 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:

$$OIL_{rate} = \frac{OIL_{unit}}{t} \quad (\text{Eq. D-9})$$

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).

**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. (This procedure is not applicable to units calculating  $NO_x$  mass emissions using the provisions of subpart H of this part.) 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<sub>e</sub> or 1000 lb of steam/hr (klb/hr) using Equation D-10 or D-11, as applicable:

$$GAS_{unit} = GAS_{meter} \left( \frac{U_{output}}{\sum_{all-units} U_{output}} \right) \quad (\text{Eq. D-10})$$

Where:

$GAS_{unit}$  = Gas flow apportioned to a unit, 100 scf.

$GAS_{meter}$  = Total gas flow through the fuel flowmeter, 100 scf.

$U_{output}$  = Total unit output, MW or klb/hr.

$$OIL_{unit} = OIL_{meter} \left( \frac{U_{output}}{\sum_{all-units} U_{output}} \right) \quad (Eq. D-11)$$

Where:

$OIL_{unit}$  = Oil flow apportioned to a unit, lb.  
 $OIL_{meter}$  = Total oil flow through the fuel flowmeter, lb.

$U_{output}$  = Total unit output in either  $MW_e$  or  $klb/hr$ .

(c) Use the total apportioned fuel flow calculated from Equation D-10 or D-11 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:

$$M_{SO_2-hr} = \sum_{all-fuels} SO_{2-rate-i} t_i \quad (Eq. D-12)$$

Where:

$M_{SO_2-hr}$  = 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,  $lb/hr$ .

$t_i$  = 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).

#### 3.5.2 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:

$$M_{SO_2-qtr} = \frac{1}{2000} \sum_{all-hours-in-qtr} M_{SO_2-hr} \quad (Eq. D-13)$$

Where:

$M_{SO_2-qtr}$  = Total mass of  $SO_2$  emissions from all fuels combusted during the quarter, tons.

$M_{SO_2-hr}$  = 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:

$$M_{SO_2-YTD} = \sum_{q=1}^{current-quarter} M_{SO_2-qtr} \quad (Eq. D-14)$$

Where:

$M_{SO_2-YTD}$  = Total  $SO_2$  mass emissions for the year to date, tons.

$M_{SO_2-qtr}$  = Total  $SO_2$  mass emissions for the quarter, tons.

#### 3.5.4 Hourly Total Heat Input from the Combustion of all Fuels

Determine the total heat input in  $mmBtu$  for each hour from the combustion of all fuels using Equation D-15:

$$HI_{hr} = \sum_{all-fuels} HI_{rate-i} t_i \quad (Eq. D-15)$$

Where:

$HI_{hr}$  = Total heat input from all fuels combusted during the hour,  $mmBtu$ .

$HI_{rate-i}$  = 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

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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).

### 3.5.5 Quarterly Heat Input

Sum the hourly heat input values determined from equation D-15 for all hours in a quarter using Equation D-16:

$$HI_{qtr} = \frac{1}{2000} \sum_{\text{all-hours-in-qtr}} HI_{hr} \quad (\text{Eq. D-16})$$

Where:

$HI_{qtr}$  = Total heat input from all fuels combusted during the quarter, mmBtu.

$HI_{hr}$  = 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.

$$HI_{YTD} = \sum_{q=1}^{\text{current-quarter}} HI_{qtr} \quad (\text{Eq. D-17})$$

$HI_{YTD}$  = 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<sub>2</sub> 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<sub>2</sub> 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 28652-28663, May 26, 1999; 64 FR 37582, July 12, 1999]

## APPENDIX E TO PART 75—OPTIONAL NO<sub>x</sub> EMISSIONS ESTIMATION PROTOCOL FOR GAS-FIRED PEAKING UNITS AND OIL-FIRED PEAKING UNITS

### 1. APPLICABILITY

#### 1.1 Unit Operation Requirements

This NO<sub>x</sub> emissions estimation procedure may be used in lieu of a continuous NO<sub>x</sub> emission monitoring system (lb/mmBtu) for determining the average NO<sub>x</sub> emission rate and hourly NO<sub>x</sub> 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, install and certify a continuous NO<sub>x</sub>

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emission monitoring system no later than December 31 of the following calendar year. The provisions 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<sub>x</sub> 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 If the owner or operator has already successfully completed certification testing of the unit using the protocol of appendix E of part 75 and submitted a certification application under §75.20(g) prior to \_\_\_\_\_ July 17, 1995, the unit's monitoring system does not need to repeat initial certification testing using the revised procedures published \_\_\_\_\_ May 17, 1995.

## 2. PROCEDURE

### 2.1 Initial Performance Testing

Use the following procedures for: measuring NO<sub>x</sub> 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<sub>x</sub> emission rate, in order to determine the emission rate of the unit(s).

#### 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<sub>x</sub> AND O<sub>2</sub> CONCENTRATION MEASUREMENTS

Use the following procedures to measure NO<sub>x</sub> and O<sub>2</sub> concentration in order to determine NO<sub>x</sub> emission rate.

2.1.2.1 For boilers, select an excess O<sub>2</sub> 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<sub>x</sub> 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<sub>x</sub> and O<sub>2</sub> at each load point for each fuel or consistent fuel combination (and, optionally, for each combination of fuels) to be combusted. Measure the NO<sub>x</sub> and O<sub>2</sub> concentrations according to method 7E and 3A in appendix A of part 60 of this chapter. Select sampling points as specified in section 5.1, method 3 in appendix A of 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, select sampling points and measure the NO<sub>x</sub> and O<sub>2</sub> concentrations at each load point for each fuel or consistent combination of fuels (and, optionally, each combination of fuels) according to appendix A, method 20 of part 60 of this chapter. For diesel or dual fuel reciprocating engines, measure the NO<sub>x</sub> and O<sub>2</sub> concentrations according to method 20, but modify method 20 by selecting a sampling site to be as close as practical 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<sub>x</sub> and O<sub>2</sub> readings to stabilize) prior to commencing NO<sub>x</sub>, O<sub>2</sub>, and heat input measurements. Determine the average measurement system response time according to section 5.5 of method 20 in appendix A, 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 average 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 average measurement 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 petition the Administrator pursuant to the procedures in §75.66 for an exemption from the requirements of this appendix for testing the NO<sub>x</sub> emission rate during combustion of the emergency fuel. The designated representative shall include in the petition a procedure for determining the NO<sub>x</sub> emission rate for the unit when the emergency fuel is combusted, and a demonstration that the permit restricts use of the fuel to emergencies only. The designated representative shall also provide notice under §75.61(a) 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<sub>x</sub> concentrations (ppm) on a dry basis (at actual excess oxygen level). Convert the NO<sub>x</sub> concentrations (ppm) to NO<sub>x</sub> emission rates (to the nearest 0.01 lb/mmBtu) 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<sub>x</sub> emission rate in lb/mmBtu for each sampling point and determine the arithmetic average NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> Emission Rate Testing

Retest the NO<sub>x</sub> emission rate of the gas-fired peaking unit or the oil-fired peaking unit prior to the earlier of 3,000 unit operating hours or the 5-year anniversary and renewal of its operating permit under part 72 of this chapter.

#### 2.3 Other Quality Assurance/Quality Control-Related NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> emission rate by the earlier of: (1) 10 unit operating days (as defined in section 2.1 of appendix B of this part) 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<sub>x</sub> emission rate. Submit test results in accordance with § 75.60(a) within 45 days of completing the retesting.

2.3.1 For a stationary gas turbine, obtain a list of at least four operating parameters indicative of the turbine's NO<sub>x</sub> formation characteristics, and the recommended ranges for these parameters at each tested load-heat input point, from the gas turbine manufacturer. If the gas turbine uses water or steam injection for NO<sub>x</sub> control, the water/fuel or

steam/fuel ratio shall be one of these parameters. During the NO<sub>x</sub>-heat input correlation tests, record the average value of each parameter for each load-heat input to ensure that the parameters are within the manufacturer's recommended range. Redetermine the NO<sub>x</sub> emission rate-heat input correlation for each fuel and (optional) combination of fuels after continuously exceeding the manufacturer's recommended 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, obtain a list of at least four operating parameters indicative of the engine's NO<sub>x</sub> formation characteristics, and the recommended ranges for these parameters at each tested load-heat input point, from the engine manufacturer. Any operating parameter critical for NO<sub>x</sub> control shall be included. During the NO<sub>x</sub> heat-input correlation tests, record the average value of each parameter for each load-heat input to ensure that the parameters are within the manufacturer's recommended range. Redetermine the NO<sub>x</sub> emission rate-heat input correlation for each fuel and (optional) combination of fuels after continuously exceeding the manufacturer's recommended 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<sub>x</sub> 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<sub>2</sub> from the boiler excess oxygen level recorded at the same operating heat input rate during the previous NO<sub>x</sub> emission rate test for one or more successive operating periods totaling more than 16 unit operating hours.

#### 2.4 Procedures for Determining Hourly NO<sub>x</sub> Emission Rate

2.4.1 Record the time (hr. and min.), load (MWge or steam load in 1000 lb/hr), 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<sub>x</sub> 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<sub>x</sub> 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 0.01 lb/mmBtu NO<sub>x</sub> (0.001 lb/mmBtu NO<sub>x</sub> after April 1, 2000). For each type of fuel, calculate NO<sub>x</sub> 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<sub>x</sub> emission rate for a unit co-firing fuels that has not been tested for that combination of fuels, interpolate between the NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> emission rate data has not been obtained according to the procedures and specifications of this appendix.

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<sub>x</sub> emission rate data using the highest NO<sub>x</sub> emission rate tabulated during the most recent set of baseline correlation tests for the same fuel or, if applicable, combination of fuels.

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<sub>x</sub> 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:

$$H_T = HI_{fuel1}t_1 + HI_{fuel2}t_2 + HI_{fuel3}t_3 + \dots + HI_{lastfuel}t_{last} \quad (\text{Eq. E-1})$$

Where:

H<sub>T</sub> = Total heat input of fuel flow or a combination of fuel flows to a unit, mmBtu.

HI<sub>fuel 1,2,3,...,last</sub> = 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<sub>1,2,3,...,last</sub> = 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)).

3.1 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:

$$H_T = HI_{fuel1} t_1 + HI_{fuel2} t_2 + HI_{fuel3} t_3 + \dots + HI_{lastfuel} t_{last} \quad (\text{Eq. E-1})$$

where:

H<sub>T</sub> = Total heat input of fuel flow or a combination of fuel flows to a unit, mmBtu;

HI<sub>fuel1,2,3,...,last</sub> = Heat input rate from each fuel during fuel usage time, in mmBtu/hr, as determined using equation F-19 or F-20 in section 5.5 of appendix F of this part, mmBtu/hr;

t<sub>1,2,3,...,last</sub> = Fuel usage time for each fuel, rounded up to the nearest .25 hours.

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 during the hour, when calculating heat input rate using equation F-19 or F-20.

### 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<sub>x</sub> Emission Rate

#### 3.3.1 Conversion from Concentration to Emission Rate

Convert the NO<sub>x</sub> concentrations (ppm) and O<sub>2</sub> concentrations to NO<sub>x</sub> 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<sub>x</sub> EMISSION RATE

Report the quarterly average emission rate (lb/mmBtu) as required in subpart G of this part. Calculate the quarterly average NO<sub>x</sub> emission rate according to equation F-9 in appendix F of this part.

#### 3.3.3 ANNUAL AVERAGE NO<sub>x</sub> 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<sub>x</sub> emission rate according to equation F-10 in appendix F of this part.

#### 3.3.4 Average NO<sub>x</sub> Emission Rate During Co-firing of Fuels

$$E_h = \frac{\sum_{f=1}^{\text{all fuels}} (E_f \times HI_f t_f)}{H_T} \quad (\text{Eq. E-2})$$

Where:

$E_h$  = NO<sub>x</sub> emission rate for the unit for the hour, lb/mmBtu.

$E_f$  = NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> emission rate load correlation testing; (3) a copy of the unit manufacturer's recommended range of quality assurance- and quality control-related operating parameters.

4.1 Submit a copy of the unit manufacturer's recommended range of operating parameter values, and the range of operating parameter values recorded during the previous NO<sub>x</sub> emission rate test that determined the unit's NO<sub>x</sub> 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 manufacturer's recommended operating range.

[58 FR 3701, Jan. 11, 1993, as amended at 60 FR 26551-26553, May 17, 1995; 64 FR 28665, May 26, 1999]

### 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<sub>2</sub> Emissions

Use the following procedures to compute hourly SO<sub>2</sub> mass emission rate (in lb/hr) and quarterly and annual SO<sub>2</sub> total mass emissions (in tons). Use the procedures in Method 19 in appendix A to part 60 of this chapter to compute hourly SO<sub>2</sub> emission rates (in lb/mmBtu) for qualifying Phase I technologies. When computing hourly SO<sub>2</sub> emission rate in lb/mmBtu, a minimum concentration of 5.0 percent CO<sub>2</sub> and a maximum concentration

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of 14.0 percent O<sub>2</sub> may be substituted for measured diluent gas concentration values at boilers during hours when the hourly average concentration of CO<sub>2</sub> is less than 5.0 percent CO<sub>2</sub> or the hourly average concentration of O<sub>2</sub> is greater than 14.0 percent O<sub>2</sub>.

2.1 When measurements of SO<sub>2</sub> concentration and flow rate are on a wet basis, use the following equation to compute hourly SO<sub>2</sub> mass emission rate (in lb/hr):

$$E_h = K C_h Q_h \quad (\text{Eq. F-1})$$

Where:

E<sub>h</sub> = Hourly SO<sub>2</sub> mass emission rate during unit operation, lb/hr.

K = 1.660 × 10<sup>-7</sup> for SO<sub>2</sub>, (lb/scf)/ppm.

C<sub>h</sub> = Hourly average SO<sub>2</sub> concentration during unit operation, stack moisture basis, ppm.

Q<sub>h</sub> = Hourly average volumetric flow rate during unit operation, stack moisture basis, scfh.

2.2 When measurements by the SO<sub>2</sub> 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<sub>2</sub> mass emission rate (in lb/hr):

$$E_h = K C_{hp} Q_{hs} \frac{(100 - \%H_2O)}{100} \quad (\text{Eq. F-2})$$

where:

E<sub>h</sub> = Hourly SO<sub>2</sub> mass emission rate during unit operation, lb/hr.

K = 1.660 × 10<sup>-7</sup> for SO<sub>2</sub>, (lb/scf)/ppm.

C<sub>hp</sub> = Hourly average SO<sub>2</sub> concentration during unit operation, ppm (dry).

Q<sub>hs</sub> = Hourly average volumetric flow rate during unit operation, scfh as measured (wet).

%H<sub>2</sub>O = Hourly average stack moisture content during unit operation, percent by volume.

2.3 Use the following equations to calculate total SO<sub>2</sub> mass emissions for each calendar quarter (Equation F-3) and for each calendar year (Equation F-4), in tons:

$$E_q = \frac{\sum_{h=i}^n E_h t_h}{2000} \quad (\text{Eq. F-3})$$

Where:

E<sub>q</sub> = Quarterly total SO<sub>2</sub> mass emissions, tons.

E<sub>h</sub> = Hourly SO<sub>2</sub> mass emission rate, lb/hr.

t<sub>h</sub> = 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<sub>2</sub> emissions values during calendar quarter.

2000 = Conversion of 2000 lb per ton.

$$E_a = \sum_{q=1}^4 E_q \quad (\text{Eq. F-4})$$

Where:

E<sub>a</sub> = Annual total SO<sub>2</sub> mass emissions, tons.

E<sub>q</sub> = Quarterly SO<sub>2</sub> mass emissions, tons.

q = Quarters for which E<sub>q</sub> are available during calendar year.

2.4 Round all SO<sub>2</sub> mass emission rates and totals to the nearest tenth.

**3. PROCEDURES FOR NO<sub>x</sub> EMISSION RATE**

Use the following procedures to convert continuous emission monitoring system measurements of NO<sub>x</sub> concentration (ppm) and diluent concentration (percentage) into NO<sub>x</sub> emission rates (in lb/mmBtu). Perform measurements of NO<sub>x</sub> and diluent (O<sub>2</sub> or CO<sub>2</sub>) concentrations on the same moisture (wet or dry) basis.

3.1 When the NO<sub>x</sub> continuous emission monitoring system uses O<sub>2</sub> as the diluent, and measurements are performed on a dry basis, use the following conversion procedure:

$$E = K C_h F \frac{20.9}{20.9 - \%O_2}$$

(Eq. F-5)

where,

K, E, C<sub>h</sub>, F, and %O<sub>2</sub> 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 of part 60 of this chapter.

3.2 When the NO<sub>x</sub> continuous emission monitoring system uses CO<sub>2</sub> as the diluent, use the following conversion procedure:

$$E = K C_h F_c \frac{100}{\%CO_2}$$

(Eq. F-6)

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where:

K, E, Ch, Fc, and %CO<sub>2</sub> are defined in section 3.3 of this appendix.

When CO<sub>2</sub> and NO<sub>x</sub> measurements are performed on a different moisture basis, use the equations in method 19 in appendix A of 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.

3.3.1  $K = 1.194 \times 10^{-7}$  (lb/dscf)/ppm NO<sub>x</sub>.

3.3.2 E = Pollutant emissions during unit operation, lb/mmBtu.

3.3.3 C<sub>n</sub> = Hourly average pollutant concentration during unit operation, ppm.

3.3.4 %O<sub>2</sub>, %CO<sub>2</sub> = Oxygen or carbon dioxide volume during unit operation (expressed as percent O<sub>2</sub> or CO<sub>2</sub>). A minimum concentration of 5.0 percent CO<sub>2</sub> and a maximum concentration of 14.0 percent O<sub>2</sub> may be substituted for measured diluent gas concentration values at boilers during hours when the hourly average concentration of CO<sub>2</sub> is < 5.0 percent CO<sub>2</sub> or the hourly average concentration of O<sub>2</sub> is > 14.0 percent O<sub>2</sub>. A minimum concentration of 1.0 percent CO<sub>2</sub> and a maximum concentration of 19.0 percent O<sub>2</sub> may be substituted for measured diluent gas concentration values at stationary gas turbines during hours when the hourly average concentration of CO<sub>2</sub> is < 1.0 percent CO<sub>2</sub> or the hourly average concentration of O<sub>2</sub> is > 19.0 percent O<sub>2</sub>.

3.3.5 F, F<sub>c</sub> = 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

CO<sub>2</sub> generated to the calorific value of the fuel combusted (F<sub>c</sub>), respectively. Table 1 lists the values of F and F<sub>c</sub> for different fuels. A minimum concentration of 5.0 percent CO<sub>2</sub> and a maximum concentration of 14.0 percent O<sub>2</sub> may be substituted for measured diluent gas concentration values during unit start-up.

TABLE 1—F- AND F<sub>c</sub>-FACTORS<sup>1</sup>

Fuel	F-factor (dscf/mmBtu)	F <sub>c</sub> -factor (scf CO <sub>2</sub> /mmBtu)
Coal (as defined by ASTM D388-92):		
Anthracite .....	10,100	1,970
Bituminous and subbituminous .....	9,780	1,800
Lignite .....	9,860	1,910
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

<sup>1</sup>Determined at standard conditions: 20 °C (68 °F) and 29.92 inches of mercury.

3.3.6 Equations F-7a and F-7b may be used in lieu of the F or F<sub>c</sub> factors specified in section 3.3.5 of this appendix to calculate an F factor (dscf/mmBtu) on a dry basis or an F<sub>c</sub> factor (scf CO<sub>2</sub>/mmBtu) on either a dry or wet basis.

(Calculate all F- and F<sub>c</sub> factors at standard conditions of 20 °C (68 °F) and 29.92 inches of mercury.)

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

(Eq. F-7a)

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

(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, "Standard Practice for Ultimate Analysis of Coal and Coke" (solid fuels), ASTM D5291-92, "Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants" (liquid fuels) or computed from results using ASTM D1945-91, "Standard Test Method for Analysis of Natural Gas

by Gas Chromatography" or ASTM D1946-90, "Standard Practice for Analysis of Reformed Gas by Gas Chromatography" (gaseous fuels) as applicable. (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 D2015-91, "Standard Test Method for Gross Calorific Value of Coal and Coke by the Adiabatic Bomb Calorimeter", ASTM D1989-92 "Standard Test Method for Gross Calorific Value of Coal and Coke by Microprocessor Controlled Isoperibol Calorimeters," or ASTM D3286-91a "Standard Test Method for Gross Calorific Value of Coal and Coke by the Isoperibol Bomb Calorimeter" for solid and liquid fuels, and ASTM D240-87 (Reapproved 1991) "Standard

Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter”, or ASTM D2382-88 “Standard Test Method for Heat of Combustion of Hydrocarbon Fuels by Bomb Calorimeter (High-Precision Method)” for oil; and ASTM D3588-91 “Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density (Specific Gravity) of Gaseous Fuels,” ASTM D4891-89 “Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion,” GPA Standard 2172 86 “Calculation of Gross Heating Value, Relative Density and Compressibility Factor for Natural Gas Mixtures from Compositional Analysis,” GPA Standard 2261-90 “Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography,” or ASTM D1826-88, “Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter” for gaseous fuels, as applicable. (These methods are incorporated by reference under §75.6).

3.3.6.3 For affected units that combust a combination of fossil (coal, oil and gas) and nonfossil (e.g., bark, wood, residue, or refuse) fuels, the F or F<sub>c</sub> value is subject to the Administrator’s approval.

3.3.6.4 For affected units that combust combinations of fossil fuels or fossil fuels and wood residue, prorate the F or F<sub>c</sub> factors determined by section 3.3.5 of this appendix in accordance with the applicable formula as follows:

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

(Eq. F-8)

where,

X<sub>i</sub> = Fraction of total heat input derived from each type of fuel (e.g., natural gas, bituminous coal, wood).

F<sub>i</sub> or (F<sub>c</sub>)<sub>i</sub> = Applicable F or F<sub>c</sub> factor for each fuel type determined in accordance with section 3.3.5 of this appendix.

n = Number of fuels being combusted in combination.

3.4 Use the following equations to calculate the average NO<sub>x</sub> emission rate for each calendar quarter (Equation F-9) and the average emission rate for the calendar year (Equation F-10), in lb/mmBtu:

$$E_q = \sum_{i=1}^n \frac{E_i}{n} \quad (\text{Eq. F-9})$$

Where:

E<sub>q</sub> = Quarterly average NO<sub>x</sub> emission rate, lb/mmBtu.

E<sub>i</sub> = Hourly average NO<sub>x</sub> emission rate during unit operation, lb/mmBtu.

n = Number of hourly rates during calendar quarter.

$$E_a = \sum_{i=1}^m \frac{E_i}{m} \quad (\text{Eq. F-10})$$

Where:

E<sub>a</sub> = Average NO<sub>x</sub> emission rate for the calendar year, lb/mmBtu.

E<sub>i</sub> = Hourly average NO<sub>x</sub> emission rate during unit operation, lb/mmBtu.

m = Number of hourly rates for which E<sub>i</sub> is available in the calendar year.

3.5 Round all NO<sub>x</sub> emission rates to the nearest 0.01 lb/mmBtu prior to April 1, 2000, and to the nearest 0.001 lb/mmBtu on and after April 1, 2000.

#### 4. PROCEDURES FOR CO<sub>2</sub> MASS EMISSIONS

Use the following procedures to convert continuous emission monitoring system measurements of CO<sub>2</sub> concentration (percentage) and volumetric flow rate (scfh) into CO<sub>2</sub> mass emissions (in tons/day) when the owner or operator uses a CO<sub>2</sub> continuous emission monitoring system (consisting of a CO<sub>2</sub> or O<sub>2</sub> pollutant monitor) and a flow monitoring system to monitor CO<sub>2</sub> emissions from an affected unit.

4.1 When CO<sub>2</sub> concentration is measured on a wet basis, use the following equation to calculate hourly CO<sub>2</sub> mass emissions rates (in tons/hr):

$$E_h = KC_h Q_h \quad (\text{Eq. F-11})$$

Where:

E<sub>h</sub> = Hourly CO<sub>2</sub> mass emission rate during unit operation, tons/hr.

K = 5.7 X 10<sup>-7</sup> for CO<sub>2</sub>, (tons/scf) /%CO<sub>2</sub>.

C<sub>h</sub> = Hourly average CO<sub>2</sub> concentration during unit operation, wet basis, percent CO<sub>2</sub>. For boilers, a minimum concentration of 5.0 percent CO<sub>2</sub> may be substituted for the measured concentration when the hourly average concentration of CO<sub>2</sub> is < 5.0 percent CO<sub>2</sub>, provided that this minimum concentration of 5.0 percent CO<sub>2</sub> is also used in the calculation of heat input for that hour. For stationary gas turbines, a minimum concentration of 1.0 percent CO<sub>2</sub> may be substituted for measured diluent gas concentration values during hours when the hourly average concentration of CO<sub>2</sub> is < 1.0 percent CO<sub>2</sub>, provided that this minimum concentration of 1.0 percent CO<sub>2</sub> is also used in the calculation of heat input for that hour.

Q<sub>h</sub> = Hourly average volumetric flow rate during unit operation, wet basis, scfh.

4.2 When CO<sub>2</sub> concentration is measured on a dry basis, use Equation F-2 to calculate the hourly CO<sub>2</sub> mass emission rate (in tons/

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hr) with a K-value of  $5.7 \times 10^{-7}$  (tons/scf) percent CO<sub>2</sub>, where E<sub>h</sub> = hourly CO<sub>2</sub> mass emission rate, tons/hr and C<sub>hp</sub> = hourly average CO<sub>2</sub> concentration in flue, dry basis, percent CO<sub>2</sub>.

4.3 Use the following equations to calculate total CO<sub>2</sub> mass emissions for each calendar quarter (Equation F-12) and for each calendar year (Equation F-13):

$$E_{CO_2q} = \sum_{h=1}^{H_R} E_h t_h \quad (\text{Eq. F-12})$$

Where:

E<sub>CO<sub>2</sub>q</sub> = Quarterly total CO<sub>2</sub> mass emissions, tons.

E<sub>h</sub> = Hourly CO<sub>2</sub> mass emission rate, tons/hr.  
t<sub>h</sub> = 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<sub>R</sub> = Number of hourly CO<sub>2</sub> mass emission rates available during calendar quarter.

$$E_{CO_2a} = \sum_{q=1}^4 E_{CO_2q} \quad (\text{Eq. F-13})$$

Where:

E<sub>CO<sub>2</sub>a</sub> = Annual total CO<sub>2</sub> mass emissions, tons.

E<sub>CO<sub>2</sub>q</sub> = Quarterly total CO<sub>2</sub> mass emissions, tons.

q = Quarters for which E<sub>CO<sub>2</sub>q</sub> are available during calendar year.

4.4 For an affected unit, when the owner or operator is continuously monitoring O<sub>2</sub> concentration (in percent by volume) of flue gases using an O<sub>2</sub> monitor, use the equations and procedures in section 4.4.1 and 4.4.2 of this appendix to determine hourly CO<sub>2</sub> mass emissions (in tons).

4.4.1 Use appropriate F and F<sub>c</sub> factors from section 3.3.5 of this appendix in one of the following equations (as applicable) to determine hourly average CO<sub>2</sub> concentration of flue gases (in percent by volume):

$$CO_{2d} = 100 \frac{F_c}{F} \frac{20.9 - O_{2d}}{20.9} \quad (\text{Eq. F-14a})$$

Where:

CO<sub>2d</sub> = Hourly average CO<sub>2</sub> concentration during unit operation, percent by volume, dry basis.

F, F<sub>c</sub> = F-factor or carbon-based F<sub>c</sub>-factor from section 3.3.5 of this appendix.

20.9 = Percentage of O<sub>2</sub> in ambient air.

O<sub>2d</sub> = Hourly average O<sub>2</sub> concentration during unit operation, percent by volume, dry basis. For boilers, a maximum concentration of 14.0 percent O<sub>2</sub> may be substituted for the measured concentration when the hourly average concentration of O<sub>2</sub> is > 14.0

percent O<sub>2</sub>, provided that this maximum concentration of 14.0 percent O<sub>2</sub> is also used in the calculation of heat input for that hour. For stationary gas turbines, a maximum concentration of 19.0 percent O<sub>2</sub> may be substituted for measured diluent gas concentration values during hours when the hourly average concentration of O<sub>2</sub> is > 19.0 percent O<sub>2</sub>, provided that this maximum concentration of 19.0 percent O<sub>2</sub> is also used in the calculation of heat input for that hour.

$$CO_{2w} = \frac{100}{20.9} \frac{F_c}{F} \left[ 20.9 \left( \frac{100 - \%H_2O}{100} \right) - O_{2w} \right] \quad (\text{Eq. F-14b})$$

Where:

CO<sub>2w</sub> = Hourly average CO<sub>2</sub> concentration during unit operation, percent by volume, wet basis.

O<sub>2w</sub> = Hourly average O<sub>2</sub> concentration during unit operation, percent by volume, wet basis. For boilers, a maximum concentration of 14.0 percent O<sub>2</sub> may be substituted for the measured concentration when the hourly average concentration of O<sub>2</sub> is > 14.0 percent O<sub>2</sub>, provided that this maximum

concentration of 14.0 percent O<sub>2</sub> is also used in the calculation of heat input for that hour. For stationary gas turbines, a maximum concentration of 19.0 percent O<sub>2</sub> may be substituted for measured diluent gas concentration values during hours when the hourly average concentration of O<sub>2</sub> is > 19.0 percent O<sub>2</sub>, provided that this maximum concentration of 19.0 percent O<sub>2</sub> is also used in the calculation of heat input for that hour.

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F, F<sub>c</sub> = F-factor or carbon-based F<sub>c</sub>-factor from section 3.3.5 of this appendix.

20.9 = Percentage of O<sub>2</sub> in ambient air.

%H<sub>2</sub>O = Moisture content of gas in the stack, percent.

4.4.2 Determine CO<sub>2</sub> mass emissions (in tons) from hourly average CO<sub>2</sub> concentration (percent by volume) using equation F-11 and the procedure in section 4.1, where O<sub>2</sub> measurements are on a wet basis, or using the procedures in section 4.2 of this appendix, where O<sub>2</sub> 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<sub>2</sub> or CO<sub>2</sub>) monitor, use the recorded data from these monitors and one of the following equations to calculate hourly heat input rate (in mmBtu/hr).

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

Where:

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

Q<sub>h</sub> = Hourly average volumetric flow rate during unit operation, wet basis, scfh.

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

%CO<sub>2d</sub> = Hourly concentration of CO<sub>2</sub> during unit operation, percent CO<sub>2</sub> dry basis. For boilers, a minimum concentration of 5.0 percent CO<sub>2</sub> may be substituted for the measured concentration when the hourly average concentration of CO<sub>2</sub> is < 5.0 percent CO<sub>2</sub>, provided that this minimum concentration of 5.0 percent CO<sub>2</sub> is also used in

5.2.1 When measurements of CO<sub>2</sub> concentration are on a wet basis, use the following equation:

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

Where:

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

Q<sub>w</sub> = Hourly average volumetric flow rate during unit operation, wet basis, scfh.

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

%CO<sub>2w</sub> = Hourly concentration of CO<sub>2</sub> during unit operation, percent CO<sub>2</sub> wet basis. For boilers, a minimum concentration of 5.0 percent CO<sub>2</sub> may be substituted for the measured concentration when the hourly average concentration of CO<sub>2</sub> is < 5.0 percent CO<sub>2</sub>, provided that this minimum concentration of 5.0 percent CO<sub>2</sub> is also used in the calculation of CO<sub>2</sub> mass emissions for that hour. For stationary gas turbines, a minimum concentration of 1.0 percent CO<sub>2</sub> may be substituted for measured diluent gas concentration values during hours when the hourly average concentration of CO<sub>2</sub> is < 1.0 percent CO<sub>2</sub>, provided that this minimum concentration of 1.0 percent CO<sub>2</sub> is also used in the calculation of CO<sub>2</sub> mass emissions for that hour.

5.2.2 When measurements of CO<sub>2</sub> concentration are on a dry basis, use the following equation:

the calculation of CO<sub>2</sub> mass emissions for that hour. For stationary gas turbines, a minimum concentration of 1.0 percent CO<sub>2</sub> may be substituted for measured diluent gas concentration values during hours when the hourly average concentration of CO<sub>2</sub> is < 1.0 percent CO<sub>2</sub>, provided that this minimum concentration of 1.0 percent CO<sub>2</sub> is also used in the calculation of CO<sub>2</sub> mass emissions for that hour.

%H<sub>2</sub>O = Moisture content of gas in the stack, percent.

5.2.3 When measurements of O<sub>2</sub> concentration are on a wet basis, use the following equation:

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

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 boilers, a maximum concentration of 14.0 percent  $O_2$  may be substituted for the measured concentration when the hourly average concentration of  $O_2$  is > 14.0 percent  $O_2$ , provided that this maximum concentration of 14.0 percent  $O_2$  is also used in

the calculation of  $CO_2$  mass emissions for that hour. For stationary gas turbines, a maximum concentration of 19.0 percent  $O_2$  may be substituted for measured diluent gas concentration values during hours when the hourly average concentration of  $O_2$  is > 19.0 percent  $O_2$ , provided that this maximum concentration of 19.0 percent  $O_2$  is also used in the calculation of  $CO_2$  mass emissions 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:

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

Where:

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

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

F = Dry basis F-factor, listed in 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. For boilers, a maximum concentration of 14.0 percent  $O_2$  may be substituted for the measured concentration when the hourly average concentration of  $O_2$  is > 14.0 percent  $O_2$ , provided that this maximum concentration of 14.0 percent  $O_2$  is also used in the calculation of  $CO_2$  mass emissions for that hour. For stationary gas turbines, a maximum concentration of 19.0 percent  $O_2$  may be substituted for measured diluent gas concentration values during hours when the hourly average concentration of  $O_2$  is > 19.0 percent  $O_2$ , provided that this maximum concentration of 19.0 percent  $O_2$  is also used in the calculation of  $CO_2$  mass emissions for that hour.

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:

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

Where:

$HI_q$  = Total heat input for the quarter, mmBtu.

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

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

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

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

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<sub>2</sub> 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<sub>x</sub> mass emissions under a State or federal NO<sub>x</sub> mass emission reduction program.

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

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

Where:

HI<sub>o</sub> = Hourly heat input rate from oil, mmBtu/hr.

M<sub>o</sub> = 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<sub>o</sub> = Gross calorific value of oil, as measured by ASTM D240-87 (Reapproved 1991), ASTM D2015-91, or ASTM D2382-88 for each oil sample under section 2.2 of appendix D to this part, Btu/unit mass (incorporated by reference under § 75.6).

10<sup>6</sup> = Conversion of Btu to mmBtu.

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

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

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

Where:

HI<sub>g</sub> = Hourly heat input rate from gaseous fuel, mmBtu/hour.

Q<sub>g</sub> = Metered flow rate of gaseous fuel combusted during unit operation, hundred cubic feet.

GCV<sub>g</sub> = 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 chro-

matograph, 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 D1826-88, ASTM D3588-91, ASTM D4891-89, GPA Standard 2172-86 "Calculation of Gross Heating Value, Relative Density and Compressibility Factor for Natural Gas Mixtures from Compositional Analysis," or GPA Standard 2261-90 "Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography," Btu/100 scf (incorporated by reference under § 75.6).

10<sup>6</sup> = 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 Method D2234-89, "Standard Test Methods for Collection of a Gross Sample of Coal," (incorporated by reference under § 75.6) 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 D2234-89 is optional, and coal samples may be taken weekly.)

5.5.3.2 Use ASTM D2013-86, "Standard Method of Preparing Coal Samples for Analysis," for preparation of a daily coal sample and analyze each daily coal sample for gross calorific value using ASTM D2015-91, "Standard Test Method for Gross Calorific Value of Coal and Coke by the Adiabatic Bomb Calorimeter", ASTM 1989-92 "Standard Test Method for Gross Calorific Value of Coal and Coke by Microprocessor Controlled Isoperibol Calorimeters," or ASTM 3286-91a "Standard Test Method for Gross Calorific Value of Coal and Coke by the Isoperibol Bomb Calorimeter." (All ASTM methods are incorporated by reference under § 75.6 of this part.)

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:

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

(Eq. F-21)

where:

HI<sub>c</sub> = Daily heat input from coal, mmBtu/day.

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

GCV<sub>c</sub> = Gross calorific value of coal sample, as measured by ASTM D3176-89, D1989-92, D3286-91a, or D2015-91, Btu/lb.

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<sub>i</sub> 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 should apportion the heat input rate using the following equation:

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

Where:

HI<sub>i</sub> = Heat input rate for a unit, mmBtu/hr.

HI<sub>CS</sub> = Heat input rate at the common stack or pipe, mmBtu/hr.

MW<sub>i</sub> = Gross electrical output, MWe.

t<sub>i</sub> = Operating time at a particular unit, 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<sub>CS</sub> = Operating time at 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).

n = Total number of units using the common stack.

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 should apportion the heat input rate using the following equation:

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

Where:

HI<sub>i</sub> = Heat input rate for a unit, mmBtu/hr.

HI<sub>CS</sub> = Heat input rate at the common stack or pipe, mmBtu/hr.

SF = Gross steam load, lb/hr.

t<sub>i</sub> = Operating time at a particular unit, 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).

$t_{CS}$  = Operating time at 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).

$n$  = Total number of units using the common stack.

$i$  = 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 should sum the heat input rates using the following equation:

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

Where:

$HI_{Unit}$  = Heat input rate for a unit, mmBtu/hr.  
 $HI_s$  = Heat input rate for each stack or duct leading from the unit, mmBtu/hr.

$t_{Unit}$  = Operating time for the unit, 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 during which the unit is exhausting through the stack or duct, 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).

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<sub>2</sub> MASS EMISSIONS AT UNITS WITH SO<sub>2</sub> CONTINUOUS EMISSION MONITORING SYSTEMS DURING THE COMBUSTION OF PIPELINE NATURAL GAS OR NATURAL GAS

The owner or operator shall use the following equation to calculate hourly SO<sub>2</sub> mass emissions as allowed for units with SO<sub>2</sub> continuous emission monitoring systems if, during the combustion of gaseous fuel that meets the definition of pipeline natural gas or natural gas in §72.2 of this chapter, SO<sub>2</sub> emissions are determined in accordance with §75.11(e)(1).

$$E_h = (ER) (HI) \quad (\text{Eq. F-23})$$

Where:

$E_h$  = Hourly SO<sub>2</sub> mass emissions, lb/hr.

$ER$  = Applicable SO<sub>2</sub> default emission rate from section 2.3.1.1 or 2.3.2.1.1 of appendix D to this part, lb/mmBtu.

$HI$  = Hourly heat input, as determined using the procedures of section 5.2 of this appendix.

8. PROCEDURES FOR NO<sub>x</sub> Mass Emissions

The owner or operator of a unit that is required to monitor, record, and report NO<sub>x</sub> mass emissions under a State or federal NO<sub>x</sub> mass emission reduction program must use the procedures in section 8.1, 8.2, or 8.3, as applicable, to account for hourly NO<sub>x</sub> mass emissions, and the procedures in section 8.4 to account for quarterly, seasonal, and annual NO<sub>x</sub> mass emissions to the extent that the provisions of subpart H of this part are adopted as requirements under such a program.

8.1 Use the following procedures to calculate hourly NO<sub>x</sub> mass emissions in lbs for the hour using hourly NO<sub>x</sub> emission rate and heat input.

8.1.1 If both NO<sub>x</sub> emission rate and heat input are monitored at the same unit or stack level (e.g. the NO<sub>x</sub> emission rate value and heat input value both represent all of the units exhausting to the common stack), use the following equation:

$$M_{(NO_x)_h} = E_{(NO_x)_h} HI_h t_h \quad (\text{Eq. F-24})$$

where:

$M_{(NO_x)_h}$  = NO<sub>x</sub> mass emissions in lbs for the hour.

$E_{(NO_x)_h}$  = Hourly average NO<sub>x</sub> emission rate for hour h, lb/mmBtu, from section 3 of this appendix, from method 19 of appendix A to part 60 of this chapter, or from section 3.3 of appendix E to this part. (Include bias-adjusted NO<sub>x</sub> 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  $\text{NO}_x$  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.

8.1.2 If  $\text{NO}_x$  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:

$$HI_{CS} = \frac{\sum_{u=1}^p HI_u t_u}{t_{CS}} \quad (\text{Eq. F-25})$$

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)(e.g., total time when any of the units which exhaust through the common stack are operating).

$HI_u$  = 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).

Use the hourly heat input rate at the common stack level and the hourly average  $\text{NO}_x$  emission rate at the common stack level and the procedures in section 8.1.1 of this appendix to determine the hourly  $\text{NO}_x$  mass emissions at the common stack.

8.1.3 If a unit has multiple ducts and  $\text{NO}_x$  emission rate is only measured at one duct, use the  $\text{NO}_x$  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  $\text{NO}_x$  mass emissions.

8.1.4 If a unit has multiple ducts and  $\text{NO}_x$  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  $\text{NO}_x$  mass emissions.

8.2 If a unit calculates  $\text{NO}_x$  mass emissions using a  $\text{NO}_x$  concentration monitoring system and a flow monitoring system, calculate hourly  $\text{NO}_x$  mass rate during unit (or stack) operation, in lb/hr, using Equation F-

1 or F-2 in this appendix (as applicable to the moisture basis of the monitors). When using Equation F-1 or F-2, replace "SO<sub>2</sub>" with "NO<sub>x</sub>" and replace the value of  $K$  with  $1.194 \times 10^{-7}$  (lb  $\text{NO}_x$  /scf)/ppm. (Include bias-adjusted flow rate or  $\text{NO}_x$  concentration values, where the bias-test procedures in appendix A to this part shows a bias-adjustment factor is necessary.)

8.3 If a unit calculates  $\text{NO}_x$  mass emissions using a  $\text{NO}_x$  concentration monitoring system and a flow monitoring system, calculate  $\text{NO}_x$  mass emissions for the hour (lb) by multiplying the hourly  $\text{NO}_x$  mass emission rate during unit operation (lb/hr) by the unit operating time during the hour, as follows:

$$M_{(\text{NO}_x)_h} = E_h t_h \quad (\text{Eq. F-26})$$

Where:

$M_{(\text{NO}_x)_h}$  =  $\text{NO}_x$  mass emissions in lbs for the hour.

$E_h$  = Hourly  $\text{NO}_x$  mass emission rate during unit (or stack) operation, lb/hr, from section 8.2 of this appendix.

$t_h$  = 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  $\text{NO}_x$  mass emission rate is 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.

8.4 Use the following procedures to calculate quarterly, cumulative ozone season, and cumulative yearly  $\text{NO}_x$  mass emissions, in tons:

$$M_{(\text{NO}_x)_{\text{time period}}} = \frac{\sum_{h=1}^p M_{(\text{NO}_x)_h}}{2000} \quad (\text{Eq. F-27})$$

Where:

$M_{(\text{NO}_x)_{\text{time period}}}$  =  $\text{NO}_x$  mass emissions in tons for the given time period (quarter, cumulative ozone season, cumulative year-to-date).

$M_{(\text{NO}_x)_h}$  =  $\text{NO}_x$  mass emissions in lbs for the hour.  $p$  = The number of hours in the given time period (quarter, cumulative ozone season, cumulative year-to-date).

8.5 Specific provisions for monitoring  $\text{NO}_x$  mass emissions from common stacks. The owner or operator of a unit utilizing a common stack may account for  $\text{NO}_x$  mass emissions using either of the following methodologies, if the provisions of subpart H are adopted as requirements of a State or federal  $\text{NO}_x$  mass reduction program:

8.5.1 The owner or operator may determine both NO<sub>x</sub> 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<sub>x</sub> mass emissions at the common stack.

8.5.2 The owner or operator may determine the NO<sub>x</sub> 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<sub>x</sub> mass emissions at each unit.

[58 FR 3701, Jan. 11, 1993; Redesignated and amended at 60 FR 26553-26556, 26571, May 17, 1995; 61 FR 25585, May 22, 1996; 61 FR 59166, Nov. 20, 1996; 63 FR 57513, Oct. 27, 1998; 64 FR 28666-28671, May 26, 1999; 64 FR 37582, July 12, 1999]

#### APPENDIX G TO PART 75— DETERMINATION OF CO<sub>2</sub> EMISSIONS

##### 1. APPLICABILITY

The procedures in this appendix may be used to estimate CO<sub>2</sub> mass emissions discharged to the atmosphere (in tons/day) as the sum of CO<sub>2</sub> emissions from combustion and, if applicable, CO<sub>2</sub> emissions from sorbent used in a wet flue gas desulfurization control system, fluidized bed boiler, or other emission controls.

##### 2. PROCEDURES FOR ESTIMATING CO<sub>2</sub> EMISSIONS FROM COMBUSTION

Use the following procedures to estimate daily CO<sub>2</sub> 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<sub>2</sub> continuous emission monitoring system or apply to the Administrator for approval of a unit-specific method for determining CO<sub>2</sub> emissions.

2.1 Use the following equation to calculate daily CO<sub>2</sub> 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<sub>2</sub> mass emissions" is replaced with the term "CO<sub>2</sub> mass emissions."

$$W_{CO_2} = \frac{(MW_C + MW_{O_2}) \times W_C}{2,000 MW_C} \quad (\text{Eq. G-1})$$

Where:

W<sub>CO<sub>2</sub></sub>=CO<sub>2</sub> emitted from combustion, tons/day.

MW<sub>C</sub>=Molecular weight of carbon (12.0).

MW<sub>O<sub>2</sub></sub>=Molecular weight of oxygen (32.0)

W<sub>C</sub> = Carbon burned, lb/day, determined using fuel sampling and analysis and fuel feed rates. 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. Determine the carbon content of each fuel sampling using one of the following methods: ASTM D3178-89 or ASTM D5373-93 for coal; ASTM D5291-92 "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 D3238-90 and either ASTM D2502-87 or ASTM D2503-82 (Reapproved 1987) for oil; and computations based on ASTM D1945-91 or ASTM D1946-90 for gas. 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<sub>2</sub> 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 D3174-89 "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 D3178-89, "Standard Test Methods for Carbon and Hydrogen in the Analysis Sample of Coal and Coke" (incorporated by reference under §75.6 of this part).

2.2.3 Discount the estimate of daily CO<sub>2</sub> mass emissions from the combustion of coal given by equation G-1 by the percent carbon retained in the ash using the following equation:

$$W_{\text{NCO}_2} = W_{\text{CO}_2} - \left( \frac{MW_{\text{CO}_2}}{MW_c} \right) \left( \frac{A\%}{100} \right) \left( \frac{C\%}{100} \right) W_{\text{COAL}}$$

where,

$W_{\text{NCO}_2}$  = Net CO<sub>2</sub> mass emissions discharged to the atmosphere, tons/day.

$W_{\text{CO}_2}$  = Daily CO<sub>2</sub> mass emissions calculated by equation G-1, tons/day.

$MW_{\text{CO}_2}$  = 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.

$W_{\text{COAL}}$  = Feed rate of coal from company records, tons/day.

2.2.4 The daily CO<sub>2</sub> mass emissions from combusting coal may be adjusted to account

for carbon retained in the ash using the following equation:

$$W_{\text{NCO}_2} = .99 W_{\text{CO}_2}$$

(Eq. G-3)

where,

$W_{\text{NCO}_2}$  = Net CO<sub>2</sub> mass emissions from the combustion of coal discharged to the atmosphere, tons/day.

.99 = Average fraction of coal converted into CO<sub>2</sub> upon combustion.

$W_{\text{CO}_2}$  = Daily CO<sub>2</sub> 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 unit as defined under §72.2 of this chapter may use the following equation and records of hourly heat input to estimate hourly CO<sub>2</sub> mass emissions (in tons).

$$W_{\text{CO}_2} = \left( \frac{F_c \times H \times U_f \times MW_{\text{CO}_2}}{2000} \right) \quad (\text{Eq. G-4})$$

(Eq. G-4)

Where:

$W_{\text{CO}_2}$  = CO<sub>2</sub> emitted from combustion, tons/hr.

$F_c$  = Carbon based F-factor, 1040 scf/mmBtu for natural gas; 1,240 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.

$U_f$  = 1/385 scf CO<sub>2</sub>/lb-mole at 14.7 psia and 68 °F.

### 3. PROCEDURES FOR ESTIMATING CO<sub>2</sub> 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<sub>2</sub> continuous emission monitoring system or an O<sub>2</sub> 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<sub>2</sub> 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<sub>2</sub> mass emissions from sorbent (in tons).

$$SE_{\text{CO}_2} = W_{\text{CaCO}_3} F_u \frac{MW_{\text{CO}_2}}{MW_{\text{CaCO}_3}}$$

(Eq. G-5)

where,

$SE_{\text{CO}_2}$  = CO<sub>2</sub> emitted from sorbent, tons/day.

$W_{\text{CaCO}_3}$  = CaCO<sub>3</sub> used, tons/day.

$F_u$  = 1.00, the calcium to sulfur stoichiometric ratio.

$MW_{\text{CO}_2}$  = Molecular weight of carbon dioxide (44).

$MW_{\text{CaCO}_3}$  = 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<sub>2</sub>-diluent continuous emission monitoring system (consisting of an SO<sub>2</sub> pollutant concentration monitor and an O<sub>2</sub> or CO<sub>2</sub> diluent gas monitor), for measuring and recording SO<sub>2</sub> emission rate (in lb/mmBtu) at the outlet to the emission controls and who uses the applicable procedures, methods, and equations in §75.15 of this part to estimate the SO<sub>2</sub> emissions removal efficiency of the emission controls, may use the following equations to estimate daily CO<sub>2</sub> mass emissions from sorbent (in tons).

$$SE_{CO_2} = F_u \frac{W_{SO_2}}{2000} \frac{MW_{CO_2}}{MW_{SO_2}}$$

(Eq. G-6)

where,

SE<sub>CO<sub>2</sub></sub>=CO<sub>2</sub> emitted from sorbent, tons/day.

MW<sub>CO<sub>2</sub></sub>=Molecular weight of carbon dioxide (44).

MW<sub>SO<sub>2</sub></sub>=Molecular weight of sulfur dioxide (64).

W<sub>SO<sub>2</sub></sub>=Sulfur dioxide removed, lb/day, as calculated below using Eq. G-7.

F<sub>u</sub>=1.0, the calcium to sulfur stoichiometric ratio.

and

$$W_{SO_2} = SO_{20} \frac{\%R}{(100 - \%R)} \quad (\text{Eq. G-7})$$

(Eq. G-7)

where:

W<sub>SO<sub>2</sub></sub> = Weight of sulfur dioxide removed, lb/day.

SO<sub>20</sub> = SO<sub>2</sub> 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<sub>2</sub> emissions removal efficiency, calculated using equations 1 through 7 in §75.15 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<sub>2</sub> mass emissions from sorbent (in tons).

3.2.1 Determine a site-specific value for F<sub>u</sub>, defined as the ratio of the number of moles of CO<sub>2</sub> released upon capture of one mole of SO<sub>2</sub>, using methods and procedures satisfactory to the Administrator. Use this value of F<sub>u</sub> (instead of 1.0) in either equation G-5 or equation G-6.

3.2.2 When using equation G-5, replace MW<sub>CaCO<sub>3</sub></sub>, the molecular weight of calcium carbonate, with the molecular weight of the sorbent material that participates in the reaction to capture SO<sub>2</sub> and that releases CO<sub>2</sub>, and replace W<sub>CaCO<sub>3</sub></sub>, 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<sub>2</sub> 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<sub>2</sub> mass emissions (in

tons) as the sum of combustion-related emissions and sorbent-related emissions.

$$W_t = W_{CO_2} + SE_{CO_2} \quad (\text{Eq. G-8})$$

where,

W<sub>t</sub> = Estimated total CO<sub>2</sub> mass emissions, tons/day.

W<sub>CO<sub>2</sub></sub> = CO<sub>2</sub> emitted from fuel combustion, tons/day.

SE<sub>CO<sub>2</sub></sub> = CO<sub>2</sub> 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<sub>2</sub> mass emissions under this appendix.

##### 5.1 Missing Carbon Content Data Prior to 4/1/2000

Prior to April 1, 2000, follow either the procedures of this section or the procedures of section 5.2 of this appendix to substitute for missing carbon content data. On and after April 1, 2000, use the procedures of section 5.2 of this appendix to substitute for missing carbon content data, not the procedures of this section.

##### 5.1.1 Most Recent Previous Data

Substitute the most recent, previous carbon content value available for that fuel type (gas, oil, or coal) of the same grade (for oil) or rank (for coal). To the extent practicable, use a carbon content value from the same fuel supply. Where no previous carbon content data are available for a particular fuel type or rank of coal, substitute the default carbon content from Table G-1 of this appendix.

##### 5.1.2 [Reserved]

##### 5.2 Missing Carbon Content Data On and After 4/1/2000

Prior to April 1, 2000, follow either the procedures of this section or the procedures of section 5.1 of this appendix to substitute for missing carbon content data. On and after April 1, 2000, use the procedures of this section 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	Sampling technique/frequency	Missing data value
Oil and coal carbon content .....	All oil and coal samples, prior to April 1, 2000.	Most recent, previous carbon content value available for that grade of oil, or default value, in this table.
Gas carbon content .....	All gaseous fuel samples, prior to April 1, 2000.	Most recent, previous carbon content value available for that type of gaseous fuel, or default value, in this table.
Default coal carbon content .....	All, on and after April 1, 2000 .....	Anthracite: 90.0 percent. Bituminous: 85.0 percent. Subbituminous/Lignite: 75.0 percent.
Default oil carbon content .....	All, on and after April 1, 2000 .....	90.0 percent.
Default gas carbon content .....	All, on and after April 1, 2000 .....	Natural gas: 75.0 percent. Other gaseous fuels: 90.0 percent.

5.3 Gross Calorific Value Data

For a gas-fired unit using the procedures of section 2.3 of this appendix to determine CO<sub>2</sub> 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 26556-26557, May 17, 1995; 61 FR 25585, May 22, 1996; 64 FR 28671, May 26, 1999]

APPENDIX H TO PART 75—REVISED TRACEABILITY PROTOCOL NO. 1 [RESERVED]

APPENDIX I TO PART 75—OPTIONAL FACTOR/FUEL FLOW METHOD [RESERVED]

APPENDIX J TO PART 75—COMPLIANCE DATES FOR REVISED RECORDKEEPING REQUIREMENTS AND MISSING DATA PROCEDURES [RESERVED]

[60 FR 26557, May 17, 1995]

**PART 76—ACID RAIN NITROGEN OXIDES EMISSION REDUCTION PROGRAM**

Sec.

- 76.1 Applicability.
- 76.2 Definitions.
- 76.3 General Acid Rain Program provisions.
- 76.4 Incorporation by reference.
- 76.5 NO<sub>x</sub> emission limitations for Group 1 boilers.
- 76.6 NO<sub>x</sub> emission limitations for Group 2 boilers.
- 76.7 Revised NO<sub>x</sub> emission limitations for Group 1, Phase II boilers.

76.8 Early election for Group 1, Phase II boilers.

76.9 Permit application and compliance plans.

76.10 Alternative emission limitations.

76.11 Emissions averaging.

76.12 Phase I NO<sub>x</sub> compliance extension.

76.13 Compliance and excess emissions.

76.14 Monitoring, recordkeeping, and reporting.

76.15 Test methods and procedures.

APPENDIX A TO PART 76—PHASE I AFFECTED COAL-FIRED UTILITY UNITS WITH GROUP 1 OR CELL BURNER BOILERS

APPENDIX B TO PART 76—PROCEDURES AND METHODS FOR ESTIMATING COSTS OF NITROGEN OXIDES CONTROLS APPLIED TO GROUP 1, PHASE I BOILERS

AUTHORITY: 42 U.S.C. 7601 and 7651 *et seq.*

SOURCE: 60 FR 18761, Apr. 13, 1995, unless otherwise noted.

**§ 76.1 Applicability.**

(a) Except as provided in paragraphs (b) through (d) of this section, the provisions apply to each coal-fired utility unit that is subject to an Acid Rain emissions limitation or reduction requirement for SO<sub>2</sub> under Phase I or Phase II pursuant to sections 404, 405, or 409 of the Act.

(b) The emission limitations for NO<sub>x</sub> under this part apply to each affected coal-fired utility unit subject to section 404(d) or 409(b) of the Act on the date the unit is required to meet the Acid Rain emissions reduction requirement for SO<sub>2</sub>.

(c) The provisions of this part apply to each coal-fired substitution unit or compensating unit, designated and approved as a Phase I unit pursuant to