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NOTICE

This unofficial version of 40 CFR Part 75 (and 40 CFR 72.1 - 72.3) has been produced to assist interested parties in understanding changes that the U.S. Environmental Protection Agency has made to Parts 72 and 75. This unofficial version contains the final rule revisions published on June 12, 2002, and also reflects proposed revisions to be published in a notice of proposed rulemaking. These proposed revisions are reproduced in the text in redline and strikeout. While all reasonable steps have been taken to produce this unofficial version in an accurate manner, the version published by the Office of the Federal Register remains the official version of the applicable rules.

For ease of electronic access, the material is split into two volumes: Volume I contains §§ 72.1 - 72.3, and the regulatory sections of Part 75; Volume II contains the appendices to Part 75.

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Appendix A to Part 75 -- Specifications and Test Procedures

App. A § 1 **1. Installation and Measurement Location**

App. A § 1.1 *1.1 Gas and Hg Monitors*

Following the procedures in section 8.1.1 of Performance Specification 2 in appendix B to part 60 of this chapter, install the pollutant concentration monitor or monitoring system at a location where the pollutant concentration and emission rate measurements are directly representative of the total emissions from the affected unit. Select a representative measurement point or path for the monitor probe(s) (or for the path from the transmitter to the receiver) such that the SO_2, CO_2, O_2, or NO_x concentration monitoring system or NO_x-diluent CEMS (NO_x pollutant concentration monitor and diluent gas monitor) Hg monitoring system, or sorbent trap monitoring system 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)

App. A § 1.1.1 1.1.1 Point Monitors

Locate the measurement point (1) within the centroidal area of the stack or duct cross section, or (2) no less than 1.0 meter from the stack or duct wall.

App. A § 1.1.2 1.1.2 Path Monitors

Locate the measurement path (1) totally within the inner area bounded by a line 1.0 meter from the stack or duct wall, or (2) such that at least 70.0 percent of the path is within the inner 50.0 percent of the stack or duct cross-sectional area, or (3) such that the path is centrally located within any part of the centroidal area.

App. A § 1.2 *1.2 Flow Monitors*

Install the flow monitor in a location that provides representative volumetric flow over all operating conditions. Such a location is one that provides an average velocity of the flue gas flow over the stack or duct cross section, provides a representative SO_2 emission rate (in lb/hr), and is representative of the pollutant concentration monitor location. Where the moisture content of the flue gas affects volumetric flow measurements, use the procedures in both Reference Methods 1 and 4 of appendix A to part 60 of this chapter to establish a proper location for the flow monitor. The EPA recommends (but does not require) performing a flow profile study following the procedures in 40 CFR part 60, appendix A, method, 1, section 2.5 or 2.4 for each of the three operating or load levels indicated in section 6.5.2.1 of this appendix to determine the acceptability of the potential flow monitor location and to determine the number and location of flow sampling points required to obtain a representative flow value. The procedure in 40 CFR part 60, appendix A, Test Method 1, section 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.

App. A § 1.2.1 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.

App. A § 1.2.2 1.2.2 Alternative Monitoring Location

Whenever the owner or operator successfully demonstrates that modifications to the exhaust duct or stack (such as installation of straightening vanes, modifications of ductwork, and the like) are necessary for the flow monitor to meet the performance specifications, the Administrator may approve an interim alternative flow monitoring methodology and an extension to the required certification date for the flow monitor.

Where no location exists that satisfies the physical siting criteria in section 1.2.1, where the results of flow profile studies performed at two or more alternative flow monitor locations are unacceptable, or where installation of a flow monitor in either the stack or the ducts is demonstrated to be technically infeasible, the owner or operator may petition the Administrator for an alternative method for monitoring flow.

App. A § 2 **2. Equipment Specifications**

App. A § 2.1 *2.1 Instrument Span and Range*

In implementing sections 2.1.1 through 2.1.6 of this appendix, set the measurement range for each parameter (SO_2, NO_x,, CO_2, O_2, or flow rate) high enough to prevent full-scale exceedances from occurring, yet low enough to ensure good measurement accuracy and to maintain a high signal-to-noise ratio. To meet these objectives, select the range such that the majority of the readings obtained during typical unit operation are kept, to the extent practicable, between 20.0 and 80.0 percent of the full-scale range of the instrument. These guidelines do not apply to: (1) SO_2 readings obtained during the combustion of very low sulfur fuel (as defined in § 72.2 of this chapter); (2) SO_2 or NO_x readings recorded on the high measurement range, for units with SO_2 or NO_x emission controls and two span values, unless the emission controls are operated seasonally (for example, only during the ozone season); or (3) SO_2 or NO_x readings less than 20.0 percent of full-scale on the low measurement range for a dual span unit, provided that the maximum expected concentration (MEC), low-scale span value, and low-scale range settings have been determined according to sections 2.1.1.2, 2.1.1.4(a), (b), and (g) of this appendix (for SO_2), or according to sections 2.1.2.2, 2.1.2.4(a) and (f) of this appendix (for NO_x).

App. A § 2.1.1 2.1.1 SO_2 Pollutant Concentration Monitors

Determine, as indicated in sections 2.1.1.1 through 2.1.1.5 of this appendix, the span value(s) and range(s) for an SO_2 pollutant concentration monitor so that all potential and expected concentrations can be accurately measured and recorded. Note that if a unit exclusively combusts fuels that are very low sulfur fuels (as defined in § 72.2 of this chapter), the SO_2 monitor span requirements in § 75.11(e)(3)(iv) apply in lieu of the requirements of this section.

App. A § 2.1.1.1 2.1.1.1 Maximum Potential Concentration

App. A § 2.1.1.1(a) (a) Make an initial determination of the maximum potential concentration (MPC) of SO_2 by using Equation A-1a or A-1b. Base the MPC calculation on the maximum percent sulfur and the minimum gross calorific value (GCV) for the highest-sulfur fuel to be burned. The maximum sulfur content and minimum GCV shall be determined from all available fuel sampling and analysis data for that fuel from the previous 12 months (minimum), excluding clearly anomalous fuel sampling values. If both the fuel sulfur content and the GCV are routinely determined from each fuel sample, the owner or operator may, as an alternative to using the highest individual percent sulfur and lowest individual GCV values in the MPC calculation, pair the sulfur content and GCV values from each sample analysis and calculate the ratio of percent sulfur to GCV (i.e., %S/GCV) for each pair of values. If this option is selected,, the MPC shall be calculated using the highest %S/GCV ratio in Equation A-1a or A-1b. If the designated representative certifies that the highest-sulfur fuel is never burned alone in the unit during normal operation but is always blended or co-fired with other fuel(s), the MPC may be calculated using a best estimate of the highest sulfur content and lowest gross calorific value expected for the blend or fuel mixture and inserting these values into Equation A-1a or A-1b. Derive the best estimate of the highest percent

sulfur and lowest GCV for a blend or fuel mixture from weighted-average values based upon the historical composition of the blend or mixture in the previous 12 (or more) months. If insufficient representative fuel sampling data are available to determine the maximum sulfur content and minimum GCV, use values from contract(s) for the fuel(s) that will be combusted by the unit in the MPC calculation.

$$MPC\ (or\ MEC) = 11.32 \times 10^6 \left(\frac{\%S}{GCV} \right) \left(\frac{20.9 - \%O_{2w}}{20.9} \right)$$

(Eq. A-1a)

or

$$MPC\ (or\ MEC) = 66.93 \times 10^6 \left(\frac{\%S}{GCV} \right) \left(\frac{\%CO_{2w}}{100} \right)$$

(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 according to the applicable method in paragraph (c) of section 2.1.1.1.
$\%O_{2w}$ = Minimum oxygen concentration, percent wet basis, under typical operating conditions.
$\%CO_{2w}$ = Maximum carbon dioxide concentration, percent wet basis, under typical operating conditions.
GCV = Minimum gross calorific value of the fuel or blend to be combusted, based on historical fuel sampling and analysis data or, if applicable, based on the fuel contract specifications (Btu/lb). If based on fuel sampling and analysis, the GCV shall be determined according to the applicable method in paragraph (c) of section 2.1.1.1.
0^6 = Oxygen-based conversion factor in Btu/lb(ppm)/%.
0^6 = Carbon dioxide-based conversion factor in Btu/lb(ppm)/%.

Note: All percent values to be inserted in the equations of this section are to be expressed as a percentage, not a fractional value (e.g., 3, not .03).

App. A § 2.1.1.1(b)

(b) Alternatively, if a certified SO_2 CEMS is already installed, the owner or operator may make the initial MPC determination based upon quality assured historical data recorded by the CEMS. For the purposes of this section, 2.1.1.1, a "certified" CEMS means a CEM system that has met the applicable certification requirements of either: this part, or part 60 of this chapter, or a State CEM program, or the source operating permit. If this option is chosen, the MPC shall be the maximum SO_2 concentration observed during the previous 720 (or more) quality assured monitor operating hours when combusting the highest-sulfur fuel (or highest-sulfur blend if fuels are always blended or co-fired) that is to be combusted in the unit or units monitored by the SO_2 monitor. For units with SO_2 emission controls, the certified SO_2 monitor used to determine the MPC must be located at or before the control device inlet. Report the MPC and the method of determination in the monitoring plan required under § 75.53. Note that the initial MPC value is subject to periodic review under section 2.1.1.5 of this appendix. If an MPC value is found to be either inappropriately high or low, the MPC shall be adjusted in accordance with section 2.1.1.5, and corresponding span and range adjustments shall be made, if necessary.

App. A § 2.1.1.1(c)

(c) When performing fuel sampling to determine the MPC, use ASTM Methods: ASTM D3177-89 (1997), "Standard Test Methods for Total Sulfur in the Analysis Sample of Coal and Coke"; ASTM ~~D4239-85~~ D4239-02, "Standard Test Methods for Sulfur in the Analysis Sample of Coal and Coke Using High Temperature Tube Furnace Combustion Methods"; ASTM ~~D4294-90~~ D4294-98, "Standard Test Method for Sulfur in Petroleum Products by Energy-Dispersive X-Ray Fluorescence Spectroscopy"; ASTM ~~D1552-90~~ D1552-01, "Standard Test Method for Sulfur in Petroleum Products (High Temperature Method)"; ASTM D129-00,

"Standard Test Method for Sulfur in Petroleum Products (General Bomb Method)"; ASTM ~~D2622-92~~ D2622-98, "Standard Test Method for Sulfur in Petroleum Products by X-Ray Spectrometry" for sulfur content of solid or liquid fuels; ASTM D3176-89 (1997)e1, "Standard Practice for Ultimate Analysis of Coal and Coke"; ASTM ~~D240-87~~ D240-00 (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~~ ASTM D5865-01ae1, "Standard Test Method for Gross Calorific Value of Coal and Coke" (incorporated by reference under § 75.6).

App. A § 2.1.1.2

2.1.1.2 Maximum Expected Concentration

App. A § 2.1.1.2(a)

(a) Make an initial determination of the maximum expected concentration (MEC) of SO_2 whenever: (a) SO_2 emission controls are used; or (b) both high-sulfur and low-sulfur fuels (e.g., high-sulfur coal and low-sulfur coal or different grades of fuel oil) or high-sulfur and low-sulfur fuel blends are combusted as primary or backup fuels in a unit without SO_2 emission controls. For units with SO_2 emission controls, use Equation A-2 to make the initial MEC determination. When high-sulfur and low-sulfur fuels or blends are burned as primary or backup fuels in a unit without SO_2 controls, use Equation A-1a or A-1b to calculate the initial MEC value for each fuel or blend, except for: (1) the highest-sulfur fuel or blend (for which the MPC was previously calculated in section 2.1.1.1 of this appendix); (2) fuels or blends that are very low sulfur fuels (as defined in § 72.2 of this chapter); or (3) fuels or blends that are used only for unit startup. Each initial MEC value shall be documented in the monitoring plan required under § 75.53. Note that each initial MEC value is subject to periodic review under section 2.1.1.5 of this appendix. If an MEC value is found to be either inappropriately high or low, the MEC shall be adjusted in accordance with section 2.1.1.5, and corresponding span and range adjustments shall be made, if necessary.

App. A § 2.1.1.2(b)

(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).

App. A § 2.1.1.2(c)

(c) Alternatively, if a certified SO_2 CEMS is already installed, the owner or operator may make the initial MEC determination(s) based upon historical monitoring data. For the purposes of this section, 2.1.1.2, a "certified" CEMS means a CEM system that has met the applicable certification requirements of either: this part, or part 60 of this chapter, or a State CEM program, or the source operating permit. If this option is chosen for a unit with SO_2 emission controls, the MEC shall be the maximum SO_2 concentration measured downstream of the control device outlet by the CEMS over the previous 720 (or more) quality assured monitor operating hours with the unit and the control device both operating normally. For units that burn high- and low-sulfur fuels or blends as primary and backup fuels and have no SO_2 emission controls, the MEC for each fuel shall be the maximum SO_2 concentration measured by the CEMS over the previous 720 (or more) quality assured monitor operating hours in which that fuel or blend was the only fuel being burned in the unit.

$$MEC = MPC\left(\frac{100 - RE}{100}\right)$$

(Eq. A-2)
Where:
MEC = Maximum expected concentration (ppm).
MPC = Maximum potential concentration (ppm), as determined by Eq. A-1a or A-1b in section 2.1.1.1 of this appendix.
RE = Expected average design removal efficiency of control equipment (%).

App. A § 2.1.1.3

2.1.1.3 Span Value(s) and Range(s)

Determine the high span value and the high full-scale range of the SO_2 monitor as follows. (Note: For purposes of this part, the high span and range refer, respectively, either to the span and range of a single span unit or to the high span and range of a dual span unit.) The high span value shall be obtained by multiplying the MPC by a factor no less than 1.00 and no greater than 1.25.

Round the span value upward to the next highest multiple of 100 ppm. If the SO_2 span concentration is ≤ 500 ppm, the span value may either be rounded upward to the next highest multiple of 10 ppm, or to the next highest multiple of 100 ppm. The high span value shall be used to determine concentrations of the calibration gases required for daily calibration error checks and linearity tests. Select the full-scale range of the instrument to be consistent with section 2.1 of this appendix and to be greater than or equal to the span value. Report the full-scale range setting and calculations of the MPC and span in the monitoring plan for the unit. Note that for certain applications, a second (low) SO_2 span and range may be required (see section 2.1.1.4 of this appendix). If an existing State, local, or federal requirement for span of an SO_2 pollutant concentration monitor requires or allows the use of a span value lower than that required by this section or by section 2.1.1.4 of this appendix, the State, local, or federal span value may be used if a satisfactory explanation is included in the monitoring plan, unless span and/or range adjustments become necessary in accordance with section 2.1.1.5 of this appendix. Span values higher than those required by either this section or section 2.1.1.4 of this appendix must be approved by the Administrator.

App. A § 2.1.1.4

2.1.1.4 Dual Span and Range Requirements

For most units, the high span value based on the MPC, as determined under section 2.1.1.3 of this appendix will suffice to measure and record SO_2 concentrations (unless span and/or range adjustments become necessary in accordance with section 2.1.1.5 of this appendix). In some instances, however, a second (low) span value based on the MEC may be required to ensure accurate measurement of all possible or expected SO_2 concentrations. To determine whether two SO_2 span values are required, proceed as follows:

App. A § 2.1.1.4(a)

(a) For units with SO_2 emission controls, compare the MEC from section 2.1.1.2 of this appendix to the high full-scale range value from section 2.1.1.3 of this appendix. If the MEC is ≥ 20.0 percent of the high range value, then the high span value and range determined under section 2.1.1.3 of this appendix are sufficient. If the MEC is < 20.0 percent of the high range value, then a second (low) span value is required.

App. A § 2.1.1.4(b)

(b) For units that combust high- and low-sulfur primary and backup fuels (or blends) and have no SO_2 controls, compare the high range value from section 2.1.1.3 of this appendix (for the highest-sulfur fuel or blend) to the MEC value for each of the other fuels or blends, as determined under section 2.1.1.2 of this appendix. If all of the MEC values are ≥ 20.0 percent of the high range value, the high span and range determined under section 2.1.1.3 of this appendix are sufficient, regardless of which fuel or blend is burned in the unit. If any MEC value is < 20.0 percent of the high range value, then a second (low) span value must be used when that fuel or blend is combusted.

App. A § 2.1.1.4(c)

(c) When two SO_2 spans are required, the owner or operator may either use a single SO_2 analyzer with a dual range (i.e., low- and high-scales) or two separate SO_2 analyzers connected to a common sample probe and sample interface. Alternatively, if RATAs are performed and passed on both measurement ranges, the owner or operator may use two separate SO_2 analyzers connected to separate probes and sample interfaces. For units with SO_2 emission controls, the owner or operator may use a low range analyzer and a default high range value, as described in paragraph (f) of this section, in lieu of maintaining and quality assuring a high-scale range. Other monitor configurations are subject to the approval of the Administrator.

App. A § 2.1.1.4(d)

(d) The owner or operator shall designate the monitoring systems and components in the monitoring plan under § 75.53 as follows: when a single probe and sample interface are used, either designate the low and high monitor ranges as separate SO_2 components of a single, primary SO_2 monitoring system; designate the low and high monitor ranges as the SO_2 components of two separate, primary SO_2 monitoring systems; designate the normal monitor range as a primary monitoring system and the other monitor range as a non-redundant backup monitoring system; or, when a single, dual-range SO_2 analyzer is used, designate the low and high ranges as a single SO_2 component of a primary SO_2 monitoring system (if this option is selected, use a special dual-range component type code, as specified by the Administrator, to satisfy the requirements of § 75.53(e)(1)(iv)(D)). When two SO_2 analyzers are connected to separate probes and sample interfaces, designate the analyzers as the SO_2 components of two separate, primary SO_2 monitoring systems. For units with SO_2 controls, if the default high range value is used, designate the low range analyzer as the SO_2 component of a primary SO_2 monitoring system. Do not

designate the default high range as a monitoring system or component. Other component and system designations are subject to approval by the Administrator. Note that the component and system designations for redundant backup monitoring systems shall be the same as for primary monitoring systems.

App. A § 2.1.1.4(e)

(e) Each monitoring system designated as primary or redundant backup shall meet the initial certification and quality assurance requirements for primary monitoring systems in § 75.20(c) or § 75.20(d)(1), as applicable, and appendices A and B to this part, with one exception: relative accuracy test audits (RATAs) are required only on the normal range (for units with SO_2 emission controls, the low range is considered normal). Each monitoring system designated as a non-redundant backup shall meet the applicable quality assurance requirements in § 75.20(d)(2).

App. A § 2.1.1.4(f)

(f) For dual span units with SO_2 emission controls, the owner or operator may, as an alternative to maintaining and quality assuring a high monitor range, use a default high range value. If this option is chosen, the owner or operator shall report a default SO_2 concentration of 200 percent of the MPC for each unit operating hour in which the full-scale of the low range SO_2 analyzer is exceeded.

App. A § 2.1.1.4(g)

(g) The high span value and range shall be determined in accordance with section 2.1.1.3 of this appendix. The low span value shall be obtained by multiplying the MEC by a factor no less than 1.00 and no greater than 1.25, and rounding the result upward to the next highest multiple of 10 ppm (or 100 ppm, as appropriate). For units that burn high- and low-sulfur primary and backup fuels or blends and have no SO_2 emission controls, select, as the basis for calculating the appropriate low span value and range, the fuel-specific MEC value closest to 20.0 percent of the high full-scale range value (from paragraph (b) of this section). The low range must be greater than or equal to the low span value, and the required calibration gases must be selected based on the low span value. However, if the default high range option in paragraph (f) of this section is selected, the full-scale of the low measurement range shall not exceed five times the MEC value (where the MEC is rounded upward to the next highest multiple of 10 ppm). For units with two SO_2 spans, use the low range whenever the SO_2 concentrations are expected to be consistently below 20.0 percent of the high full-scale range value, i.e., when the MEC of the fuel or blend being combusted is less than 20.0 percent of the high full-scale range value. When the full-scale of the low range is exceeded, the high range shall be used to measure and record the SO_2 concentrations; or, if applicable, the default high range value in paragraph (f) of this section shall be reported for each hour of the full-scale exceedance.

App. A § 2.1.1.5

2.1.1.5 Adjustment of Span and Range

For each affected unit or common stack, the owner or operator shall make a periodic evaluation of the MPC, MEC, span, and range values for each SO_2 monitor (at a minimum, an annual evaluation is required) and shall make any necessary span and range adjustments, with corresponding monitoring plan updates, as described in paragraphs (a), (b), and (c) of this section. Span and range adjustments may be required, for example, as a result of changes in the fuel supply, changes in the manner of operation of the unit, or installation or removal of emission controls. In implementing the provisions in paragraphs (a) and (b) of this section, SO_2 data recorded during short-term, non-representative process operating conditions (e.g., a trial burn of a different type of fuel) shall be excluded from consideration. The owner or operator shall keep the results of the most recent span and range evaluation on-site, in a format suitable for inspection. Make each required span or range adjustment no later than 45 days after the end of the quarter in which the need to adjust the span or range is identified, except that up to 90 days after the end of that quarter may be taken to implement a span adjustment if the calibration gases currently being used for daily calibration error tests and linearity checks are unsuitable for use with the new span value.

App. A § 2.1.1.5(a)

(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.

App. A § 2.1.1.5(b) (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:

App. A § 2.1.1.5(b)(1) (1) For exceedances of the high range, report 200.0 percent of the current full-scale range as the hourly SO_2 concentration for each hour of the full-scale exceedance and make appropriate adjustments to the MPC, span, and range to prevent future full-scale exceedances.

App. A § 2.1.1.5(b)(2) (2) For units with two SO_2 spans and ranges, if the low range is exceeded, no further action is required, provided that the high range is available and its most recent calibration error test and linearity check have not expired. ~~is not out-of-control or out-of-service for any reason.~~ However, if either of these quality assurance tests has expired and the high range is not able to provide quality assured data at the time of the low range exceedance or at any time during the continuation of the exceedance, report the MPC as the SO_2 concentration until the readings return to the low range or until the high range is able to provide quality assured data (unless the reason that the high-scale range is not able to provide quality assured data is because the high-scale range has been exceeded; if the high-scale range is exceeded follow the procedures in paragraph (b)(1) of this section).

App. A § 2.1.1.5(c) (c) Whenever changes are made to the MPC, MEC, full-scale range, or span value of the SO_2 monitor, as described in paragraphs (a) or (b) of this section, record and report (as applicable) the new full-scale range setting, the new MPC or MEC and calculations of the adjusted span value in an updated monitoring plan. The monitoring plan update shall be made in the quarter in which the changes become effective. In addition, record and report the adjusted span as part of the records for the daily calibration error test and linearity check specified by appendix B to this part. Whenever the span value is adjusted, use calibration gas concentrations that meet the requirements of section 5.1 of this appendix, based on the adjusted span value. When a span adjustment is so significant that the calibration gases currently being used for daily calibration error tests and linearity checks are unsuitable for use with the new span value, then a diagnostic linearity test using the new calibration gases must be performed and passed. Use the data validation procedures in § 75.20(b)(3), beginning with the hour in which the span is changed.

App. A § 2.1.2 2.1.2 NO_x Pollutant Concentration Monitors

Determine, as indicated in sections 2.1.2.1 through 2.1.2.5 of this appendix, the span and range value(s) for the NO_x pollutant concentration monitor so that all expected NO_x concentrations can be determined and recorded accurately.

App. A § 2.1.2.1 2.1.2.1 Maximum Potential Concentration

App. A § 2.1.2.1(a) (a) The maximum potential concentration (MPC) of NO_x for each affected unit shall be based upon whichever fuel or blend combusted in the unit produces the highest level of NO_x emissions. For the purposes of this section, 2.1.2.1, and section 2.1.2.2 of this appendix, a "blend" means a frequently-used fuel mixture having a consistent composition (e.g., an oil and gas mixture where the relative proportions of the two fuels vary by no more than 10%, on average). Make an initial determination of the MPC using the appropriate option as follows:

Option 1: Use 800 ppm for coal-fired and 400 ppm for oil- or gas-fired units as the maximum potential concentration of NO_x (if an MPC of 1600 ppm for coal-fired units or 480 ppm for oil- or gas-fired units was previously selected under this section, that value may still be used, provided that the guidelines of section 2.1 of this appendix are met). For cement kilns, use 2000 ppm as the MPC. For process heaters, use 200 ppm if the unit burns only gaseous fuel and 500 ppm if the unit burns oil;

Option 2: Use the specific values based on boiler type and fuel combusted, listed in Table 2-1 or Table 2-2. For a new gas-fired or oil-fired combustion turbine, if a default MPC value of 50 ppm was previously selected from Table 2-2, that value may be used until March 31, 2003;

Option 3: Use NO_x emission test results;

Option 4: Use historical CEM data over the previous 720 (or more) unit operating hours

when combusting the fuel or blend with the highest NO_x emission rate; or

Option 5: If a reliable estimate of the uncontrolled NO_x emissions from the unit is available from the manufacturer, the estimated value may be used.

App. A § 2.1.2.1(b)

(b) For the purpose of providing substitute data during NO_x missing data periods in accordance with §§ 75.31 and 75.33 and as required elsewhere under this part, the owner or operator shall also calculate the maximum potential NO_x emission rate (MER), in lb/mmBtu, by substituting the MPC for NO_x in conjunction with the minimum expected CO_2 or maximum O_2 concentration (under all unit operating conditions except for unit startup, shutdown, and upsets) and the appropriate F-factor into the applicable equation in appendix F to this part. The diluent cap value of 5.0 percent CO_2 (or 14.0 percent O_2) for boilers or 1.0 percent CO_2 (or 19.0 percent O_2) for combustion turbines may be used in the NO_x MER calculation. As a second alternative, when the NO_x MPC is determined from emission test results or from historical CEM data, as described in paragraphs (a), (d) and (e) of this section, quality-assured diluent gas (i.e., O_2 or CO_2) data recorded concurrently with the MPC may be used to calculate the MER.

App. A § 2.1.2.1(c)

(c) Report the method of determining the initial MPC and the calculation of the maximum potential NO_x emission rate in the monitoring plan for the unit. Note that whichever MPC option in paragraph 2.1.2.1(a) of this appendix is selected, the initial MPC value is subject to periodic review under section 2.1.2.5 of this appendix. If an MPC value is found to be either inappropriately high or low, the MPC shall be adjusted in accordance with section 2.1.2.5, and corresponding span and range adjustments shall be made, if necessary.

App. A § 2.1.2.1(d)

(d) For units with add-on NO_x controls (whether or not the unit is equipped with low-NO_x burner technology), or for units equipped with dry low-NO_x (DLN) technology, NO_x emission testing may only be used to determine the MPC if testing can be performed either upstream of the add-on controls or during a time or season when the add-on controls are not in operation or when the DLN controls are not in the premixed (low-NO_x) mode. If NO_x emission testing is performed, use the following guidelines. Use Method 7E from appendix A to part 60 of this chapter to measure total NO_x concentration. (Note: Method 20 from appendix A to part 60 may be used for gas turbines, instead of Method 7E.) Operate the unit, or group of units sharing a common stack, at the minimum safe and stable load, the normal load, and the maximum load. If the normal load and maximum load are identical, an intermediate level need not be tested. Operate at the highest excess O_2 level expected under normal operating conditions. Make at least three runs of 20 minutes (minimum) duration with three traverse points per run at each operating condition. Select the highest point NO_x concentration from all test runs as the MPC for NO_x.

App. A § 2.1.2.1(e)

(e) If historical CEM data are used to determine the MPC, the data must, for uncontrolled units or units equipped with low-NO_x burner technology and no other NO_x controls, represent a minimum of 720 quality assured monitor operating hours from the NO_x component of a certified monitoring system, obtained under various operating conditions including the minimum safe and stable load, normal load (including periods of high excess air at normal load), and maximum load. For the purposes of this section, 2.1.2.1, a "certified" CEMS means a CEM system that has met the applicable certification requirements of either: this part, or part 60 of this chapter, or a State CEM program, or the source operating permit. For a unit with add-on NO_x controls (whether or not the unit is equipped with low-NO_x burner technology), or for a unit equipped with dry low-NO_x (DLN) technology, historical CEM data may only be used to determine the MPC if the 720 quality assured monitor operating hours of CEM data are collected upstream of the add-on controls or if the 720 hours of data include periods when the add-on controls are not in operation or when the DLN controls are not in the premixed (low-NO_x mode). For units that do not produce electrical or thermal output, the data must represent the full range of normal process operation. The highest hourly NO_x concentration in ppm shall be the MPC.

TABLE 2-1. -- MAXIMUM POTENTIAL CONCENTRATION FOR NO_x -- Coal-Fired Units

Unit type	Maximum potential concentration for NO_x (ppm)
Tangentially-fired dry bottom and fluidized bed	460
Wall-fired dry bottom, turbo-fired dry bottom, stokers	675
Roof-fired (vertically-fired) dry bottom, cell burners, arch-fired	975
Cyclone, wall-fired wet bottom, wet bottom turbo-fired	1200
Others	(1)

[1] As approved by the Administrator

TABLE 2-2. -- MAXIMUM POTENTIAL CONCENTRATION FOR NO_X -- Gas- And Oil-Fired Units

Unit type	Maximum potential concentration for NO_x (ppm)
Tangentially-fired dry bottom	380
Wall-fired dry bottom	600
Roof-fired (vertically-fired) dry bottom, arch-fired	550
Existing combustion turbine	200
New combustion turbine, permitted to fire either oil or natural gas	200
New combustion turbine, permitted to fire only natural gas	150
Others	(1)

[1] As approved by the Administrator

App. A § 2.1.2.2 2.1.2.2 Maximum Expected Concentration

App. A § 2.1.2.2(a) (a) Make an initial determination of the maximum expected concentration (MEC) of NO_x during normal operation for affected units with add-on NO_x controls of any kind (e.g., steam injection, water injection, SCR, or SNCR) and for turbines that use dry low-NO_x technology. Determine a separate MEC value for each type of fuel (or blend) combusted in the unit, except for fuels that are only used for unit startup and/or flame stabilization. Calculate the MEC of NO_x using Equation A-2, if applicable, inserting the maximum potential concentration, as determined using the procedures in section 2.1.2.1 of this appendix. Where Equation A-2 is not applicable, set the MEC either by: (1) measuring the NO_x concentration using the testing procedures in this section; (2) using historical CEM data over the previous 720 (or more) quality assured monitor operating hours; or (3) if the unit has add-on NO_x controls or uses dry low NO_x technology, and has a federally-enforceable permit limit for NO_x concentration, the permit limit may be used as the MEC. Include in the monitoring plan for the unit each MEC value and the method by which the MEC was determined. Note that each initial MEC value is subject to periodic review under section 2.1.2.5 of this appendix. If an MEC value is found to be either inappropriately high or low, the MEC shall be adjusted in accordance with section 2.1.2.5, and corresponding span and range adjustments shall be made, if necessary.

App. A § 2.1.2.2(b) (b) If NO_x emission testing is used to determine the MEC value(s), the MEC for each type of fuel (or blend) shall be based upon testing at minimum load, normal load, and maximum load. At least three tests of 20 minutes (minimum) duration, using at least three traverse points, shall be performed at each load, using Method 7E from appendix A to part 60 of this chapter (Note:

Method 20 from appendix A to part 60 may be used for gas turbines instead of Method 7E). The test must be performed at a time when all NO_x control devices and methods used to reduce NO_x emissions (if applicable) are operating properly. The testing shall be conducted downstream of all NO_x controls. The highest point NO_x concentration (e.g., the highest one-minute average) recorded during any of the test runs shall be the MEC.

App. A § 2.1.2.2(c)

(c) If historical CEM data are used to determine the MEC value(s), the MEC for each type of fuel shall be based upon 720 (or more) hours of quality assured data from the NO_x component of a certified monitoring system, representing the entire load range under stable operating conditions. For the purposes of this section, 2.1.2.2, a "certified" CEMS means a CEM system that has met the applicable certification requirements of either: this part, or part 60 of this chapter, or a State CEM program, or the source operating permit. The data base for the MEC shall not include any CEM data recorded during unit startup, shutdown, or malfunction or (for units with add-on NO_x controls or turbines using dry low NO_x technology) during any NO_x control device malfunctions or outages. All NO_x control devices and methods used to reduce NO_x emissions (if applicable) must be operating properly during each hour. The CEM data shall be collected downstream of all NO_x controls. For each type of fuel, the highest of the 720 (or more) quality assured hourly average NO_x concentrations recorded by the CEMS shall be the MEC.

App. A § 2.1.2.3

2.1.2.3 Span Value(s) and Range(s)

(a) Determine the high span value of the NO_x monitor as follows. The high span value shall be obtained by multiplying the MPC by a factor no less than 1.00 and no greater than 1.25. Round the span value upward to the next highest multiple of 100 ppm. If the NO_x span concentration is $\leq$ 500 ppm, the span value may either be rounded upward to the next highest multiple of 10 ppm, or to the next highest multiple of 100 ppm. The high span value shall be used to determine the concentrations of the calibration gases required for daily calibration error checks and linearity tests. Note that for certain applications, a second (low) NO_x span and range may be required (see section 2.1.2.4 of this appendix).

(b) If an existing State, local, or federal requirement for span of a NO_x pollutant concentration monitor requires or allows the use of a span value lower than that required by this section or by section 2.1.2.4 of this appendix, the State, local, or federal span value may be used, where a satisfactory explanation is included in the monitoring plan, unless span and/or range adjustments become necessary in accordance with section 2.1.2.5 of this appendix. Span values higher than required by this section or by section 2.1.2.4 of this appendix must be approved by the Administrator.

(c) Select the full-scale range of the instrument to be consistent with section 2.1 of this appendix and to be greater than or equal to the high span value. Include the full-scale range setting and calculations of the MPC and span in the monitoring plan for the unit.

App. A § 2.1.2.4

2.1.2.4 Dual Span and Range Requirements

For most units, the high span value based on the MPC, as determined under section 2.1.2.3 of this appendix will suffice to measure and record NO_x concentrations (unless span and/or range adjustments must be made in accordance with section 2.1.2.5 of this appendix). In some instances, however, a second (low) span value based on the MEC may be required to ensure accurate measurement of all expected and potential NO_x concentrations. To determine whether two NO_x spans are required, proceed as follows:

App. A § 2.1.2.4(a)

(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.

App. A § 2.1.2.4(b)

(b) When two NO_x spans are required, the owner or operator may either use a single NO_x analyzer with a dual range (low- and high-scales) or two separate NO_x analyzers connected to a common sample probe and sample interface. Two separate NO_x analyzers connected to separate probes and sample interfaces may be used if RATAs are passed on both ranges. For units with add-on NO_x emission controls (e.g., steam injection, water injection, SCR, or SNCR) or units equipped with dry low-NO_x technology, the owner or operator may use a low range analyzer and a

"default high range value," as described in paragraph 2.1.2.4(e) of this section, in lieu of maintaining and quality assuring a high-scale range. Other monitor configurations are subject to the approval of the Administrator.

App. A § 2.1.2.4(c)

(c) The owner or operator shall designate the monitoring systems and components in the monitoring plan under § 75.53 as follows: when a single probe and sample interface are used, either designate the low and high ranges as separate NO_x components of a single, primary NO_x monitoring system; designate the low and high ranges as the NO_x components of two separate, primary NO_x monitoring systems; designate the normal range as a primary monitoring system and the other range as a non-redundant backup monitoring system; or, when a single, dual-range NO_x analyzer is used, designate the low and high ranges as a single NO_x component of a primary NO_x monitoring system (if this option is selected, use a special dual-range component type code, as specified by the Administrator, to satisfy the requirements of § 75.53(e)(1)(iv)(D)). When two NO_x analyzers are connected to separate probes and sample interfaces, designate the analyzers as the NO_x components of two separate, primary NO_x monitoring systems. For units with add-on NO_x controls or units equipped with dry low-NO_x technology, if the default high range value is used, designate the low range analyzer as the NO_x component of the primary NO_x monitoring system. Do not designate the default high range as a monitoring system or component. Other component and system designations are subject to approval by the Administrator. Note that the component and system designations for redundant backup monitoring systems shall be the same as for primary monitoring systems.

App. A § 2.1.2.4(d)

(d) Each monitoring system designated as primary or redundant backup shall meet the initial certification and quality assurance requirements in § 75.20(c) (for primary monitoring systems), in § 75.20(d)(1) (for redundant backup monitoring systems) and appendices A and B to this part, with one exception: relative accuracy test audits (RATAs) are required only on the normal range (for dual span units with add-on NO_x emission controls, the low range is considered normal). Each monitoring system designated as non-redundant backup shall meet the applicable quality assurance requirements in § 75.20(d)(2).

App. A § 2.1.2.4(e)

(e) For dual span units with add-on NO_x emission controls (e.g., steam injection, water injection, SCR, or SNCR),or, for units that use dry low-NO_x premix technology, the owner or operator may, as an alternative to maintaining and quality assuring a high monitor range, use a default high range value. If this option is chosen, the owner or operator shall report a default value of 200.0 percent of the MPC for each unit operating hour in which the full-scale of the low range NO_x analyzer is exceeded.

App. A § 2.1.2.4(f)

(f) The high span and range shall be determined in accordance with section 2.1.2.3 of this appendix. The low span value shall be 100.0 to 125.0 percent of the MEC, rounded up to the next highest multiple of 10 ppm (or 100 ppm, if appropriate). If more than one MEC value (as determined in section 2.1.2.2 of this appendix) is < 20.0 percent of the high full-scale range value, the low span value shall be based upon whichever MEC value is closest to 20.0 percent of the high range value. The low range must be greater than or equal to the low span value, and the required calibration gases for the low range must be selected based on the low span value. However, if the default high range option in paragraph (e) of this section is selected, the full-scale of the low measurement range shall not exceed five times the MEC value (where the MEC is rounded upward to the next highest multiple of 10 ppm). For units with two NO_x spans, use the low range whenever NO_x concentrations are expected to be consistently < 20.0 percent of the high range value, i.e., when the MEC of the fuel being combusted is < 20.0 percent of the high range value. When the full-scale of the low range is exceeded, the high range shall be used to measure and record the NO_x concentrations; or, if applicable, the default high range value in paragraph (e) of this section shall be reported for each hour of the full-scale exceedance.

App. A § 2.1.2.5

2.1.2.5 Adjustment of Span and Range

For each affected unit or common stack, the owner or operator shall make a periodic evaluation of the MPC, MEC, span, and range values for each NO_x monitor (at a minimum, an annual evaluation is required) and shall make any necessary span and range adjustments, with corresponding monitoring plan updates, as described in paragraphs (a) 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), (b), and (c) of this section, note that NO_x data

recorded during short-term, non-representative operating conditions (e.g., a trial burn of a different type of fuel) shall be excluded from consideration. The owner or operator shall keep the results of the most recent span and range evaluation on-site, in a format suitable for inspection. Make each required span or range adjustment no later than 45 days after the end of the quarter in which the need to adjust the span or range is identified, except that up to 90 days after the end of that quarter may be taken to implement a span adjustment if the calibration gases currently being used for daily calibration error tests and linearity checks are unsuitable for use with the new span value.

App. A § 2.1.2.5(a)

(a) If the fuel supply, emission controls, or other process parameters change such that the maximum expected concentration or the maximum potential concentration changes significantly, adjust the NO_x pollutant concentration span(s) and (if necessary) monitor range(s) to assure the continued accuracy of the monitoring system. A "significant" change in the MPC or MEC means that the guidelines in section 2.1 of this appendix can no longer be met, as determined by either a periodic evaluation by the owner or operator or from the results of an audit by the Administrator. The owner or operator should evaluate whether any planned changes in operation of the unit or stack may affect the concentration of emissions being emitted from the unit and should plan any necessary span and range changes needed to account for these changes, so that they are made in as timely a manner as practicable to coordinate with the operational changes. An example of a change that may require a span and range adjustment is the installation of low-NO_x burner technology on a previously uncontrolled unit. Determine the adjusted span(s) using the procedures in section 2.1.2.3 or 2.1.2.4 of this appendix (as applicable). Select the full-scale range(s) of the instrument to be greater than or equal to the adjusted span value(s) and to be consistent with the guidelines of section 2.1 of this appendix.

App. A § 2.1.2.5(b)

(b) Whenever a full-scale range is exceeded during a quarter and the exceedance is not caused by a monitor out-of-control period, proceed as follows:

(1) For exceedances of the high range, report 200.0 percent of the current full-scale range as the hourly NO_x concentration for each hour of the full-scale exceedance and make appropriate adjustments to the MPC, span, and range to prevent future full-scale exceedances.

(2) For units with two NO_x spans and ranges, if the low range is exceeded, no further action is required, provided that the high range is available and its most recent calibration error test and linearity check have not expired. ~~is not out-of-control or out-of-service for any reason.~~ However, if either of these quality assurance tests has expired and the high range is not able to provide quality assured data at the time of the low range exceedance or at any time during the continuation of the exceedance, report the MPC as the NO_x concentration until the readings return to the low range or until the high range is able to provide quality assured data (unless the reason that the high-scale range is not able to provide quality assured data is because the high-scale range has been exceeded; if the high-scale range is exceeded, follow the procedures in paragraph (b)(1) of this section).

App. A § 2.1.2.5(c)

(c) Whenever changes are made to the MPC, MEC, full-scale range, or span value of the NO_x monitor as described in paragraphs (a) and (b) of this section, record and report (as applicable) the new full-scale range setting, the new MPC or MEC, maximum potential NO_x emission rate, and the adjusted span value in an updated monitoring plan for the unit. The monitoring plan update shall be made in the quarter in which the changes become effective. In addition, record and report the adjusted span as part of the records for the daily calibration error test and linearity check required by appendix B to this part. Whenever the span value is adjusted, use calibration gas concentrations that meet the requirements of section 5.1 of this appendix, based on the adjusted span value. When a span adjustment is significant enough that the calibration gases currently being used for daily calibration error tests and linearity checks are unsuitable for use with the new span value, a diagnostic linearity test using the new calibration gases must be performed and passed. Use the data validation procedures in § 75.20(b)(3), beginning with the hour in which the span is changed.

App. A § 2.1.3

2.1.3 CO_2 and O_2 Monitors

For an O_2 monitor (including O_2 monitors used to measure CO_2 emissions or percentage moisture), select a span value between 15.0 and 25.0 percent O_2. For a CO_2 monitor installed on a boiler, select a span value between 14.0 and 20.0 percent CO_2. For a CO_2 monitor installed on a combustion turbine, an alternative span value between 6.0 and 14.0 percent CO_2 may be used. An alternative CO_2 span value below 6.0 percent may be used if an appropriate technical justification is included in the hardcopy monitoring plan. An alternative O_2 span value below 15.0 percent O_2 may be used if an appropriate technical justification is included in the monitoring plan (e.g., O_2

concentrations above a certain level create an unsafe operating condition). Select the full-scale range of the instrument to be consistent with section 2.1 of this appendix and to be greater than or equal to the span value. Select the calibration gas concentrations for the daily calibration error tests and linearity checks in accordance with section 5.1 of this appendix, as percentages of the span value. For O_2 monitors with span values $\geq$ 21.0 percent O_2, purified instrument air containing 20.9 percent O_2 may be used as the high-level calibration material. If a dual-range or autoranging diluent analyzer is installed, the analyzer may be represented in the monitoring plan as a single component, using a special component type code specified by the Administrator to satisfy the requirements of § 75.53(e)(1)(iv)(D).

App. A § 2.1.3.1

2.1.3.1 Maximum Potential Concentration of CO_2

For CO_2 pollutant concentration monitors, the maximum potential concentration shall be 14.0 percent CO_2 for boilers and 6.0 percent CO_2 for combustion turbines. Alternatively, the owner or operator may determine the MPC based on a minimum of 720 hours of quality assured historical CEM data representing the full operating load range of the unit(s). Note that the MPC for CO_2 monitors shall only be used for the purpose of providing substitute data under this part. The CO_2 monitor span and range shall be determined according to section 2.1.3 of this appendix.

App. A § 2.1.3.2

2.1.3.2 Minimum Potential Concentration of O_2

The owner or operator of a unit that uses a flow monitor and an O_2 diluent monitor to determine heat input in accordance with Equation F-17 or F-18 in appendix F to this part shall, for the purposes of providing substitute data under § 75.36, determine the minimum potential O_2 concentration. The minimum potential O_2 concentration shall be based upon 720 hours or more of quality-assured CEM data, representing the full operating load range of the unit(s). The minimum potential O_2 concentration shall be the lowest quality-assured hourly average O_2 concentration recorded in the 720 (or more) hours of data used for the determination.

App. A § 2.1.3.3

2.1.3.3 Adjustment of Span and Range

The MPC and MEC values for diluent monitors are subject to the same periodic review as SO_2 and NO_x monitors (see sections 2.1.1.5 and 2.1.2.5 of this appendix). If an MPC or MEC value is found to be either inappropriately high or low, the MPC shall be adjusted and corresponding span and range adjustments shall be made, if necessary. Adjust the span value and range of a CO_2 or O_2 monitor in accordance with section 2.1.1.5 of this appendix (insofar as those provisions are applicable), with the term "CO_2 or O_2" applying instead of the term "SO_2". Set the new span and range in accordance with section 2.1.3 of this appendix and report the new span value in the monitoring plan.

App. A § 2.1.4

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.

App. A § 2.1.4.1

2.1.4.1 Maximum Potential Velocity and Flow Rate

For this purpose, determine the span value of the flow monitor using the following procedure. Calculate the maximum potential velocity (MPV) using Equation A-3a or A-3b or determine the MPV (wet basis) from velocity traverse testing using Reference Method 2 (or its allowable alternatives) in appendix A to part 60 of this chapter. If using test values, use the highest average velocity (determined from the Method 2 traverses) measured at or near the maximum unit operating load (or, for units that do not produce electrical or thermal output, at the normal process operating conditions corresponding to the maximum stack gas flow rate). Express the MPV in units of wet standard feet per minute (fpm). For the purpose of providing substitute data during periods of missing flow rate data in accordance with §§ 75.31 and 75.33 and as required elsewhere in this part, calculate the maximum potential stack gas flow rate (MPF) in units of standard cubic feet per hour (scfh), as the product of the MPV (in units of wet, standard fpm) times 60, times the cross-sectional area of the stack or duct (in ft^2) at the flow monitor location.

$$MPV = \left(\frac{F_d H_f}{A} \right) \left(\frac{20.9}{20.9 - \% O_{2d}} \right) \left(\frac{100}{100 - \% H_2O} \right)$$

(Eq. A-3a)

or

$$MPV = \left(\frac{F_c H_f}{A} \right) \left(\frac{100}{\% CO_{2d}} \right) \left(\frac{100}{100 - \% H_2O} \right)$$

(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 CO_2/mmBtu) from Table 1, Appendix F to this part.
Hf = maximum heat input (mmBtu/minute) for all units, combined, exhausting to the stack or duct where the flow monitor is located.
A = inside cross sectional area (ft^2) of the flue at the flow monitor location.
$\%O_{2d}$ = maximum oxygen concentration, percent dry basis, under normal operating conditions.
$\%CO_{2d}$ = minimum carbon dioxide concentration, percent dry basis, under normal operating conditions.
$\%H_2O$ = maximum percent flue gas moisture content under normal operating conditions.

App. A § 2.1.4.2

2.1.4.2 Span Values and Range

Determine the span and range of the flow monitor as follows. Convert the MPV, as determined in section 2.1.4.1 of this appendix, to the same measurement units of flow rate that are used for daily calibration error tests (e.g., scfh, kscfh, kacfm, or differential pressure (inches of water)). Next, determine the "calibration span value" by multiplying the MPV (converted to equivalent daily calibration error units) by a factor no less than 1.00 and no greater than 1.25, and rounding up the result to at least two significant figures. For calibration span values in inches of water, retain at least two decimal places. Select appropriate reference signals for the daily calibration error tests as percentages of the calibration span value, as specified in section 2.2.2.1 of this appendix. Finally, calculate the "flow rate span value" (in scfh) as the product of the MPF, as determined in section 2.1.4.1 of this appendix, times the same factor (between 1.00 and 1.25) that was used to calculate the calibration span value. Round off the flow rate span value to the nearest 1000 scfh. Select the full-scale range of the flow monitor so that it is greater than or equal to the span value and is consistent with section 2.1 of this appendix. Include in the monitoring plan for the unit: calculations of the MPV, MPF, calibration span value, flow rate span value, and full-scale range (expressed both in scfh and, if different, in the measurement units of calibration).

App. A § 2.1.4.3

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.

App. A § 2.1.4.3(a)

(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.

App. A § 2.1.4.3(b)

(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.

App. A § 2.1.4.3(c)

(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).

App. A § 2.1.5

2.1.5 Minimum Potential Moisture Percentage

Except as provided in section 2.1.6 of this appendix, the owner or operator of a unit that uses a continuous moisture monitoring system to correct emission rates and heat inputs from a dry basis to a wet basis (or vice-versa) shall, for the purpose of providing substitute data under § 75.37, use a default value of 3.0 percent H_2O as the minimum potential moisture percentage. Alternatively, the minimum potential moisture percentage may be based upon 720 hours or more of quality-assured CEM data, representing the full operating load range of the unit(s). If this option is chosen, the minimum potential moisture percentage shall be the lowest quality-assured hourly average H_2O concentration recorded in the 720 (or more) hours of data used for the determination.

App. A § 2.1.6

2.1.6 Maximum Potential Moisture Percentage

When Equation 19-3, 19-4 or 19-8 in Method 19 in appendix A to part 60 of this chapter is used to determine NO_x emission rate, the owner or operator of a unit that uses a continuous moisture monitoring system shall, for the purpose of providing substitute data under § 75.37, determine the maximum potential moisture percentage. The maximum potential moisture percentage shall be based upon 720 hours or more of quality-assured CEM data, representing the full operating load range of the unit(s). The maximum potential moisture percentage shall be the highest quality-assured hourly average H_2O concentration recorded in the 720 (or more) hours of data used for the determination. Alternatively, a default maximum potential moisture value of 15.0 percent H_2O may be used.

App. A § 2.1.7

2.1.7 Hg Monitors

Determine the appropriate span and range value(s) for each Hg pollutant concentration monitor, so that all expected Hg concentrations can be determined accurately.

App. A § 2.1.7.1

2.1.7.1 Maximum Potential Concentration

(a) The maximum potential concentration depends upon the type of coal combusted in the unit. For the initial MPC determination, there are three options:

(1) Use one of the following default values: 9 μg/scm for bituminous coal; 10 μg/scm for

sub-bituminous coal; 16 μg/scm for lignite, and 1 μg/scm for waste coal, i.e., anthracite culm or bituminous gob. If different coals are blended, use the highest MPC for any fuel in the blend; or

(2) You may base the MPC on the results of site-specific emission testing using the one of the Hg reference methods in § 75.22, if the unit does not have add-on Hg emission controls or a flue gas desulfurization system, or if you test upstream of these control devices. A minimum of 3 test runs are required, at the normal operating load. Use the highest total Hg concentration obtained in any of the tests as the MPC; or

(3) You may base the MPC on 720 or more hours of historical CEMS data or data from a sorbent trap monitoring system, if the unit does not have add-on Hg emission controls or a flue gas desulfurization system (or if the CEMS or sorbent trap system is located upstream of these control devices) and if the Hg CEMS or sorbent trap system has been tested for relative accuracy against one of the Hg reference methods in § 75.22 and has met a relative accuracy specification of 20.0% or less.

(b) For the purposes of missing data substitution, the fuel-specific or site-specific MPC values defined in paragraph (a) of this section apply to units using sorbent trap monitoring systems.

App. A § 2.1.7.2

2.1.7.2 Maximum Expected Concentration

For units with FGD systems that significantly reduce Hg emissions (including fluidized bed units that use limestone injection) and for units equipped with add-on Hg emission controls (e.g., carbon injection), determine the maximum expected Hg concentration (MEC) during normal, stable operation of the unit and emission controls. To calculate the MEC, substitute the MPC value from section 2.1.7.1 of this appendix into Equation A–2 in section 2.1.1.2 of this appendix. For units with add-on Hg emission controls, base the percent removal efficiency on design engineering calculations. For units with FGD systems, use the best available estimate of the Hg removal efficiency of the FGD system.

App. A § 2.1.7.3

2.1.7.3 Span and Range Value(s)

(a) For each Hg monitor, determine a high span value, by rounding the MPC value from section 2.1.7.1 of this appendix upward to the next highest multiple of 10 μg/scm.

(b) For an affected unit equipped with an FGD system or a unit with add-on Hg emission controls, if the MEC value from section 2.1.7.2 of this appendix is less than 20 percent of the high span value from paragraph (a) of this section, and if the high span value is 20 μg/scm or greater, define a second, low span value of 10 μg/scm.

(c) If only a high span value is required, set the full-scale range of the Hg analyzer to be greater than or equal to the span value.

(d) If two span values are required, you may either:

(1) Use two separate (high and low) measurement scales, setting the range of each scale to be greater than or equal to the high or low span value, as appropriate; or

(2) Quality-assure two segments of a single measurement scale.

App. A § 2.1.7.4

2.1.7.4 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 Hg monitor (at a minimum, an annual evaluation is required) and shall make any necessary span and range adjustments, with corresponding monitoring plan updates. 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, data recorded during short-term, nonrepresentative process operating conditions (e.g., a trial burn of a different type of fuel) shall be excluded from consideration. The owner or operator shall keep the results of the most recent span and range evaluation on-site, in a format suitable for inspection. Make each required span or range adjustment no later than 45 days after the end of the quarter in which the need to adjust the span or range is identified, except that up to 90 days after the end of that quarter may be taken to implement a span adjustment if the calibration gas concentrations currently being used for calibration error tests, system integrity checks, and linearity checks are unsuitable for use with the new span value and new calibration materials must be ordered.

(a) The guidelines of section 2.1 of this appendix do not apply to Hg monitoring systems.

(b) Whenever a full-scale range exceedance occurs during a quarter and is not caused by a monitor out-of-control period, proceed as follows:

(1) For monitors with a single measurement scale, report 200 percent of the full-scale range as the hourly Hg concentration until the readings come back on-scale and if appropriate, make adjustments to the MPC, span, and range to prevent future full-scale exceedances; or

(2) For units with two separate measurement scales, 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 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 Hg monitor, 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 gas concentrations currently being used for calibration error tests, system integrity checks and linearity checks are unsuitable for use with the new span value, then a diagnostic linearity or 3-level system integrity check using the new calibration gas concentrations must be performed and passed. Use the data validation procedures in § 75.20(b)(3), beginning with the hour in which the span is changed.

App. A § 2.2

2.2 Design for Quality Control Testing

App. A, § 2.2.1

2.2.1 Pollutant Concentration and CO_2 or O_2 Monitors

(a) Design and equip each pollutant concentration and CO_2 or O_2 monitor with a calibration gas injection port that allows a check of the entire measurement system when calibration gases are introduced. For extractive and dilution type monitors, all monitoring components exposed to the sample gas, (e.g., sample lines, filters, scrubbers, conditioners, and as much of the probe as practicable) are included in the measurement system. For in situ type monitors, the calibration must check against the injected gas for the performance of all active electronic and optical components (e.g. transmitter, receiver, analyzer).

(b) Design and equip each pollutant concentration or CO_2 or O_2 monitor to allow daily determinations of calibration error (positive or negative) at the zero- and mid- or high-level concentrations specified in section 5.2 of this appendix.

App. A, § 2.2.2

2.2.2 Flow Monitors

Design all flow monitors to meet the applicable performance specifications.

2.2.2.1 Calibration Error Test

Design and equip each flow monitor to allow for a daily calibration error test consisting of at least two reference values: Zero to 20 percent of span or an equivalent reference value (e.g., pressure pulse or electronic signal) and 50 to 70 percent of span. Flow monitor response, both before and after any adjustment, must be capable of being recorded by the data acquisition and handling system. Design each flow monitor to allow a daily calibration error test of the entire flow monitoring system, from and including the probe tip (or equivalent) through and including the data acquisition and handling system, or the flow monitoring system from and including the transducer through and including the data acquisition and handling system.

2.2.2.2 Interference Check

(a) Design and equip each flow monitor with a means to ensure that the moisture expected to occur at the monitoring location does not interfere with the proper functioning of the flow monitoring system. Design and equip each flow monitor with a means to detect, on at least a daily basis, pluggage of each sample line and sensing port, and malfunction of each resistance temperature detector (RTD), transceiver or equivalent.

(b) Design and equip each differential pressure flow monitor to provide an automatic, periodic

back purging (simultaneously on both sides of the probe) or equivalent method of sufficient force and frequency to keep the probe and lines sufficiently free of obstructions on at least a daily basis to prevent velocity sensing interference, and a means for detecting leaks in the system on at least a quarterly basis (manual check is acceptable).

(c) Design and equip each thermal flow monitor with a means to ensure on at least a daily basis that the probe remains sufficiently clean to prevent velocity sensing interference.

(d) Design and equip each ultrasonic flow monitor with a means to ensure on at least a daily basis that the transceivers remain sufficiently clean (e.g., backpurging system) to prevent velocity sensing interference.

App. A, § 2.2.3

2.2.3 Mercury Monitors.

Design and equip each mercury monitor to permit the introduction of known concentrations of elemental Hg and $HgCl_2$ separately, at a point immediately preceding the sample extraction filtration system, such that the entire measurement system can be checked. If the Hg monitor does not have a converter, the $HgCl_2$ injection capability is not required.

App. A § 3

3. Performance Specifications

App. A § 3.1

3.1 Calibration Error

(a) The calibration error performance specifications in this section apply only to 7-day calibration error tests under sections 6.3.1 and 6.3.2 of this appendix and to the offline calibration demonstration described in section 2.1.1.2 of appendix B to this part. The calibration error limits for daily operation of the continuous monitoring systems required under this part are found in section 2.1.4(a) of appendix B to this part.

(b) The calibration error of SO_2 and NO_x pollutant concentration monitors shall not deviate from the reference value of either the zero or upscale calibration gas by more than 2.5 percent of the span of the instrument, as calculated using Equation A-5 of this appendix. Alternatively, where the span value is less than 200 ppm, calibration error test results are also acceptable if the absolute value of the difference between the monitor response value and the reference value, $|R-A|$ in Equation A-5 of this appendix, is $\leq$ 5 ppm. The calibration error of CO_2 or O_2 monitors (including O_2 monitors used to measure CO_2 emissions or percent moisture) shall not deviate from the reference value of the zero or upscale calibration gas by > 0.5 percent O_2 or CO_2, as calculated using the term $|R-A|$ in the numerator of Equation A-5 of this appendix. The calibration error of flow monitors shall not exceed 3.0 percent of the calibration span value of the instrument, as calculated using Equation A-6 of this appendix. For differential pressure-type flow monitors, the calibration error test results are also acceptable if $|R-A|$, the absolute value of the difference between the monitor response and the reference value in Equation A-6, does not exceed 0.01 inches of water.

(c) The calibration error of a Hg concentration monitor shall not deviate from the reference value of either the zero or upscale calibration gas by more than 5.0 percent of the span value, as calculated using Equation A–5 of this appendix. Alternatively, if the span value is 10 μg/scm, the 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 < 1.0 μg/scm.

App. A § 3.2

3.2 Linearity Check

For SO_2 and NO_x pollutant concentration monitors, the error in linearity for each calibration gas concentration (low-, mid-, and high-levels) shall not exceed or deviate from the reference value by more than 5.0 percent (as calculated using equation A-4 of this appendix). Linearity check results are also acceptable if the absolute value of the difference between the average of the monitor response values and the average of the reference values, $|R-A|$ in equation A-4 of this appendix, is less than or equal to 5 ppm. For CO_2 or O_2 monitors (including O_2 monitors used to measure CO_2 emissions or percent moisture):

(1) The error in linearity for each calibration gas concentration (low-, mid-, and high-levels) shall not exceed or deviate from the reference value by more than 5.0 percent as calculated using equation A-4 of this appendix; or

(2) The absolute value of the difference between the average of the monitor response values and the average of the reference values, $|R-A|$ in equation A-4 of this appendix, shall be less than or equal to 0.5 percent CO_2 or O_2, whichever is less restrictive.

(3) For the linearity check and the 3-level system integrity check of an Hg monitor, which are required, respectively, under §§75.20(c)(1)(ii) and (c)(1)(vi), the measurement error shall not exceed 5.0 percent of the span value at any of the three gas levels. To calculate the measurement error at each level, take the absolute value of the difference between the reference value and mean CEM response, divide the result by the span value, and then multiply by 100. Alternatively, the results at any gas level are acceptable if the absolute value of the difference between the average monitor response and the average reference value, i.e., | R – A | in Equation A-4 of this appendix, does not exceed 0.6 $\mu g/m^3$. The principal and alternative performance specifications in this section also apply to the single-level system integrity check described in section 2.6 of appendix B to this part.

~~For Hg monitors:~~

~~(i) 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 10.0 percent as calculated using equation A–4 of this appendix; or~~

~~(ii) 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 1.0 µg/scm, whichever is less restrictive.~~

~~(iii) For the 3-level system integrity check required under § 75.20(c)(1)(vi), the system measurement error shall not exceed 5.0 percent of the span value at any of the three gas levels. To calculate the measurement error at each level, take the absolute value of the difference between the reference value and mean CEM response, divide the result by the span value, and then multiply by 100.~~

App. A § 3.3 *3.3 Relative Accuracy*

App. A § 3.3.1 3.3.1 Relative Accuracy for SO_2 Monitors

(a) The relative accuracy for SO_2 pollutant concentration monitors shall not exceed 10.0 percent except as provided in this section.

(b) For affected units where the average of the reference method measurements of SO_2 concentration during the relative accuracy test audit is less than or equal to 250.0 ppm, the difference between the mean value of the monitor measurements and the reference method mean value shall not exceed +15.0 ppm, wherever the relative accuracy specification of 10.0 percent is not achieved.

App. A § 3.3.2 3.3.2 Relative Accuracy for NO_x-Diluent Continuous Emission Monitoring Systems

(a) The relative accuracy for NO_x-diluent continuous emission monitoring systems shall not exceed 10.0 percent.

(b) For affected units where the average of the reference method measurements of NO_x emission rate during the relative accuracy test audit is less than or equal to 0.200 lb/mmBtu, the difference between the mean value of the continuous emission monitoring system measurements and the reference method mean value shall not exceed + 0.020 lb/mmBtu, wherever the relative accuracy specification of 10.0 percent is not achieved.

App. A § 3.3.3 3.3.3 Relative Accuracy for CO_2 and O_2 Monitors

The relative accuracy for CO_2 and O_2 monitors shall not exceed 10.0 percent. The relative accuracy test results are also acceptable if the difference between the mean value of the CO_2 or O_2 monitor measurements and the corresponding reference method measurement mean value, calculated using equation A-7 of this appendix, does not exceed ± 1.0 percent CO_2 or O_2.

App. A § 3.3.4 3.3.4 Relative Accuracy for Flow Monitors

(a) The relative accuracy of flow monitors shall not exceed 10.0 percent at any load (or operating) level at which a RATA is performed (i.e., the low, mid, or high level, as defined in section 6.5.2.1 of this appendix).

(b) For affected units where the average of the flow reference method measurements of gas velocity at a particular load (or operating) level of the relative accuracy test audit is less than or equal to 10.0 fps, the difference between the mean value of the flow monitor velocity measurements and the reference method mean value in fps at that level shall not exceed + 2.0 fps, wherever the

10.0 percent relative accuracy specification is not achieved.

App. A § 3.3.5 3.3.5 Combined SO_2/Flow Monitoring System [Reserved]

App. A § 3.3.6 3.3.6 Relative Accuracy for Moisture Monitoring Systems

The relative accuracy of a moisture monitoring system shall not exceed 10.0 percent. The relative accuracy test results are also acceptable if the difference between the mean value of the reference method measurements (in percent H_2O) and the corresponding mean value of the moisture monitoring system measurements (in percent H_2O), calculated using Equation A-7 of this appendix does not exceed ± 1.5 percent H_2O.

App. A § 3.3.7 3.3.7 Relative Accuracy for NO_x Concentration Monitoring Systems

(a) The following requirement applies only to NO_x concentration monitoring systems (i.e., NO_x pollutant concentration monitors) that are used to determine NO_x mass emissions, where the owner or operator elects to monitor and report NO_x mass emissions using a NO_x concentration monitoring system and a flow monitoring system.

(b) The relative accuracy for NO_x concentration monitoring systems shall not exceed 10.0 percent. Alternatively, for affected units where the average of the reference method measurements of NO_x concentration during the relative accuracy test audit is less than or equal to 250.0 ppm, the difference between the mean value of the continuous emission monitoring system measurements and the reference method mean value shall not exceed + 15.0 ppm, wherever the 10.0 percent relative accuracy specification is not achieved.

App. A § 3.3.8 3.3.8 Relative Accuracy for Hg Monitoring Systems

The relative accuracy of a Hg concentration monitoring system or a sorbent trap monitoring system shall not exceed 20.0 percent. Alternatively, for affected units where the average of the reference method measurements of Hg concentration during the relative accuracy test audit is less than 5.0 μg/scm, the test results are acceptable if the difference between the mean value of the monitor measurements and the reference method mean value does not exceed 1.0 μg/scm, in cases where the relative accuracy specification of 20.0 percent is not achieved.

App. A § 3.4 *3.4 Bias*

App. A § 3.4.1 3.4.1 SO_2 Pollutant Concentration Monitors, NO_x Concentration Monitoring Systems and NO_x-Diluent Continuous Emission Monitoring Systems

SO_2 pollutant concentration monitors, NO_x-diluent continuous emission monitoring systems and NO_x concentration monitoring systems used to determine NO_x mass emissions, as defined in § 75.71(a)(2), shall not be biased low as determined by the test procedure in section 7.6 of this appendix. The bias specification applies to all SO_2 pollutant concentration monitors and to all NO_x concentration monitoring systems, including those measuring an average SO_2 or NO_x concentration of 250.0 ppm or less, and to all NO_x-diluent continuous emission monitoring systems, including those measuring an average NO_x emission rate of 0.200 lb/mmBtu or less.

App. A § 3.4.2 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.

App. A § 3.4.3 3.4.3 Hg Monitoring Systems

Mercury concentration monitoring systems and sorbent trap monitoring systems shall not be biased low as determined by the test procedure in section 7.6 of this appendix.

App. A § 3.5 *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.

App. A § 4 **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. These systems also shall have the capability of interpreting and converting the individual output signals from an SO_2 pollutant concentration monitor, a flow monitor, a CO_2 monitor, an O_2 monitor, a NO_x pollutant concentration monitor, and a NO_x-diluent CEMS, a Hg concentration monitoring system, and a sorbent trap monitoring system to produce a continuous readout of pollutant emission rates or pollutant mass emissions (as applicable) in the appropriate units (e.g., lb/hr, lb/mmBtu, ounces/hour, tons/hr).

Data acquisition and handling systems shall also compute and record monitor calibration error; any bias adjustments to SO_2, NO_X, and Hg pollutant concentration data, flow rate data, Hg emission rate data, or NO_x 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 the appropriate units (e.g., lb/hr of SO_2, lb/mmBtu of NO_x);

(4) Predict and record NO_x emission rate using the heat input rate and the NO_x/heat input correlation developed under appendix E of this part;

(5) Calculate and record all missing data substitution values specified in appendix D or E of this part; and

(6) Provide a continuous, permanent record of all measurements and required information 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.

App. A § 5 **5. Calibration Gas**

App. A § 5.1 *5.1 Reference Gases*

For the purpose~~s~~ of part 75, calibration gases include the following~~.~~:

App. A § 5.1.1 5.1.1 ~~Standard Reference Materials (SRM)~~EPA Protocol Gases

~~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, Maryland 20899-0001.~~ (a) An EPA Protocol Gas is a calibration gas mixture prepared and analyzed according to Section 2 of the "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards," September 1997, EPA-600/R-97/121 or such revised procedure as approved by the Administrator (EPA Traceability Protocol).

(b) An EPA Protocol Gas must have a specialty gas producer-certified uncertainty (95-percent confidence interval) that must not be greater than 2.0 percent of the certified concentration (tag value) of the gas mixture. The uncertainty must be calculated using the statistical procedures (or equivalent statistical techniques) that are listed in Section 2.1.8 of the EPA Traceability Protocol.

(c) A specialty gas producer advertising calibration gas certification with the EPA Traceability Protocol or distributing calibration gases as "EPA Protocol Gas" must participate in the EPA Protocol Gas Verification Program (PGVP) described in Section 2.1.10 of the EPA Traceability Protocol or it cannot use "EPA" in any form of advertising for these products, unless approved by the Administrator. A specialty gas producer may not certify a calibration gas as an EPA Protocol Gas unless it participates in the PGVP, unless approved by the Administrator.

(d) A copy of EPA-600/R-97/121 is available from the National Technical Information Service, 5285 Port Royal Road, Springfield, VA, 703-605-6585 or http://www.ntis.gov, and from

http://www.epa.gov/ttn/emc/news.html or http://www.epa.gov/appcdwww/tsb/index.html.

App. A § 5.1.2

5.1.2 ~~SRM-Equivalent Compressed Gas Primary Reference Material (PRM)~~Mercury Standards

~~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.~~ For 7-day calibration error tests of Hg concentration monitors and for daily calibration error tests of Hg monitors, either elemental Hg standards or a NIST-traceable source of oxidized Hg may be used. For linearity checks, elemental Hg standards shall be used. For 3-level and single-point system integrity checks under §75.20(c)(1)(vi), sections 6.2(g) and 6.3.1 of this appendix, and sections 2.1.1, 2.2.1 and 2.6 of appendix B to this part, a NIST-traceable source of oxidized Hg shall be used. Alternatively, other NIST-traceable standards may be used for the required checks, subject to the approval of the Administrator.

App. A § 5.1.3

5.1.3 ~~NIST Traceable Reference Materials~~Zero Air Material

~~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.~~ (a) A calibration gas certified by the specialty gas producer or vendor not to contain concentrations of SO_2, NO_x, or total hydrocarbons above 0.1 parts per million (ppm), a concentration of CO above 1 ppm, or a concentration of CO_2 above 400 ppm;

(b) Ambient air conditioned and purified by a CEMS for which the CEMS manufacturer or vendor certifies that the particular CEMS model produces conditioned gas that does not contain concentrations of SO_2, NO_x, or total hydrocarbons above 0.1 ppm, a concentration of CO above 1 ppm, or a concentration of CO_2 above 400 ppm;

(c) For dilution-type CEMS, conditioned and purified ambient air provided by a conditioning system concurrently supplying dilution air to the CEMS; or

(d) A multi-component mixture certified by the supplier of the mixture that the concentration of the component being zeroed is less than or equal to the applicable concentration specified in paragraph (a) of this section, and that the mixture's other components do not interfere with the CEM readings.

App. A § 5.1.4

~~5.1.4 EPA Protocol Gases~~

~~(a) EPA Protocol gGases must have a vendor-certified uncertainty (95-percent confidence interval) that does not exceed 2.0 percent of the certified concentration (tag value) of the gas mixture. The uncertainty must be calculated using the statistical procedure (or equivalent) that are listed in Section 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 (EPA Traceability Protocol, as amended on August 25, 1999) or such revised protocol as may be approved by the Administrator. Vendors claiming that their calibration gases conform to the EPA Traceability Protocol or advertising their calibration gases as "EPA Protocal Gas" must participate in the EPA Protocol Gas Verification Program. Non-participating vendors are prohibited from using "EPA" in any form of advertising for their calibration gases unless approved by the Administrator.~~

~~(b) A copy of EPA-600/R-97/121 is available from the National Technical Information Service, 5285 Port Royal Road, Springfield, VA, 703-605-6585 or http://www.ntis.gov, and from http://www.epa.gov/ttn/emc/news.html or http://www.epa.gov/appcdwww/tsb/index.html. or the Office of Research and Development, (MD-77B), U.S. Environmental Protection Agency, Research Triangle Park, NC 27711.~~

App. A § 5.1.5

~~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.~~

App. A § 5.1.6 ~~5.1.6 Zero Air Material~~

~~Zero air material is defined in § 72.2 of this chapter.~~

App. A § 5.1.7 ~~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.~~

App. A § 5.1.8 5.1.~~8~~4 Gas Manufacturer's Intermediate Standards

Gas manufacturer's intermediate standards is defined in § 72.2 of this chapter.

App. A § 5.1.9 ~~*5.1.9 Mercury Standards.*~~

~~For 7-day calibration error tests of Hg concentration monitors and for daily calibration error tests of Hg monitors, either elemental Hg standards or a NIST-traceable source of oxidized Hg may be used. For linearity checks, elemental Hg standards shall be used. For 3-level and single-point system integrity checks under § 75.20(c)(1)(vi), sections 6.2(g) and 6.3.1 of this appendix, and sections 2.1.1, 2.2.1 and 2.6 of appendix B to this part, a NISTtraceable source of oxidized Hg shall be used. Alternatively, other NIST-traceable standards may be used for the required checks, subject to the approval of the Administrator.~~

App. A § 5.2 *5.2 Concentrations*

Four concentration levels are required as follows.

5.2.1 Zero-level Concentration

0.0 to 20.0 percent of span, including span for high-scale or both low- and high-scale for SO_2, NO_x, CO_2, and O_2 monitors, as appropriate.

5.2.2 Low-level Concentration

20.0 to 30.0 percent of span, including span for high-scale or both low- and high-scale for SO_2, NO_x, CO_2, and O_2 monitors, as appropriate.

5.2.3 Mid-level Concentration

50.0 to 60.0 percent of span, including span for high-scale or both low- and high-scale for SO_2, NO_x, CO_2, and O_2 monitors, as appropriate.

5.2.4 High-level Concentration

80.0 to 100.0 percent of span, including span for high-scale or both low- and high-scale for SO_2, NO_x, CO_2, and O_2 monitors, as appropriate.

App. A § 6 **6. Certification Tests and Procedures**

App. A § 6.1 *6.1 General Requirements*

App. A § 6.1.1 6.1.1 Pretest Preparation

Install the components of the continuous emission monitoring system (i.e., pollutant concentration monitors, CO_2 or O_2 monitor, and flow monitor) as specified in sections 1, 2, and 3 of this appendix, and prepare each system component and the combined system for operation in accordance with the manufacturer's written instructions. Operate the unit(s) during each period when measurements are made. Units may be tested on non-consecutive days. To the extent practicable, test the DAHS software prior to testing the monitoring hardware.

App. A § 6.1.2 6.1.2 Requirements for Air Emission Testing Bodies

App. A § 6.1.2(a) (a) Any Air Emission Testing Body (AETB) conducting relative accuracy test audits of CEMS and sorbant trap monitoring systems under this part must conform to the requirements of ASTM D7036-04. This section is not applicable to daily operation, daily calibration error checks, daily flow interference checks, quarterly linearity checks or routine maintenance of CEMS.

App. A § 6.1.2(b) (b) The AETB shall provide to the affected source(s) certification that the AETB operates in conformance with, and that data submitted to the Agency has been collected in accordance with, the requirements of ASTM D7036-04. This certification may be provided in the form of:

(1) A certificate of accreditation of relevant scope issued by a recognized, national accreditation body; or

(2) A letter of certification signed by a member of the senior management staff of the AETB.

App. A § 6.1.2(c) (c) The AETB shall either provide a Qualified Individual on-site to conduct or shall oversee all relative accuracy testing carried out by the AETB as required in ASTM D7036-04. The Qualified Individual shall provide the affected source(s) with copies of the qualification credentials relevant to the scope of the testing conducted.

App. A § 6.2 6.2 *Linearity Check (General Procedures)*

Check the linearity of each SO_2, NO_x, CO_2, Hg, and O_2 monitor while the unit, or group of units for a common stack, is combusting fuel at conditions of typical stack temperature and pressure; it is not necessary for the unit to be generating electricity during this test. Notwithstanding these requirements, if the SO_2 or NO_x span value for a particular monitor range is ≤ 30 ppm, that range is exempted from the linearity ~~test~~ check requirements of this part, both for initial certification and for on-going quality assurance. For units with two measurement ranges (high and low) for a particular parameter, perform a linearity check on both the low scale (except for SO_2 or NO_x span values ≤ 30 ppm) and the high scale. Note that for a NO_x-diluent monitoring system with two NO_x measurement ranges, if the low NO_x scale has a span value ≤ 30 ppm and is exempt from linearity checks, this does not exempt either the diluent monitor or the high NO_x scale (if the span is > 30 ppm) from linearity check requirements. ~~For 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:

App. A § 6.2(a) (a) For the initial certification of a CEMS, data from the monitoring system are considered invalid until all certification tests, including the linearity test, have been successfully completed, unless the conditional data validation procedures in § 75.20(b)(3) are used. When the procedures in § 75.20(b)(3) are followed, the words "initial certification" apply instead of "recertification," and complete all of the initial certification tests by the applicable deadline in § 75.4, rather than within the time periods specified in § 75.20(b)(3)(iv) for the individual tests.

App. A § 6.2(b) (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.

App. A § 6.2(c) (c) When a linearity test is required as a diagnostic test or for recertification, use the data validation procedures in § 75.20(b)(3).

App. A § 6.2(d) (d) For linearity tests of non-redundant backup monitoring systems, use the data validation procedures in § 75.20(d)(2)(iii).

App. A § 6.2(e) (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.

App. A § 6.2(f) (f) For all other linearity checks, use the data validation procedures in section 2.2.3 of appendix B to this part.

App. A § 6.2(g) (g) For Hg monitors, follow the guidelines in section 2.2.3 of this appendix in addition to the applicable procedures in ~~this~~ section 6.2 when performing the ~~3-level~~ system integrity checks described in § 75.20(c)(1)(vi) and in sections 2.1.1, ~~2.6~~ 2.2.1 and 2.6 of appendix B to this part.

App. A § 6.2(h) (h) For Hg concentration monitors, if moisture is added to the calibration gas during the required linearity checks or system integrity checks, and if the Hg monitor measures on a dry basis, the moisture content of the calibration gas must be accounted for. Under these circumstances, the dry basis concentration of the calibration gas shall be used to calculate the linearity error or measurement error (as applicable).

App. A § 6.3 *6.3 7-Day Calibration Error Test*

App. A § 6.3.1 6.3.1 Gas Monitor 7-day Calibration Error Test

The following monitors and ranges are exempted from the 7-day calibration error test requirements of this part: the SO_2, NO_x, CO_2 and O_2 monitors installed on peaking units (as defined in § 72.2 of this chapter); and any SO_2 or NO_x measurement range with a span value of 50 ppm or less. In all other cases, measure the calibration error of each SO_2 monitor, each NO_x monitor, each Hg concentration monitor, and each CO_2 or O_2 monitor while the unit is combusting fuel (but not necessarily generating electricity) once each day for 7 consecutive operating days according to the following procedures. For Hg monitors, you may perform this test using either elemental Hg standards or a NIST-traceable source of oxidized Hg. (In the event that unit outages occur after the commencement of the test, the 7 consecutive unit operating days need not be 7 consecutive calendar days.) Also for Hg monitors, if moisture is added to the calibration gas and the monitoring system measures Hg concentration on a dry basis, the added moisture must be accounted for and the dry-basis concentration of the calibration gas shall be used to calculate the calibration error. 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_2 and NO_x pollutant concentration monitors using the low-scale for units equipped with emission controls or other units with dual span monitors. Use only calibration gas, as specified in section 5.1 of this appendix. Introduce the calibration gas at the gas injection port, as specified in section 2.2.1 of this appendix. Operate each monitor in its normal sampling mode. For extractive and dilution type monitors, pass the calibration gas through all filters, scrubbers, conditioners, and other monitor components used during normal sampling and through as much of the sampling probe as is practical. For in-situ type monitors, perform calibration, checking all active electronic and optical

components, including the transmitter, receiver, and analyzer. Challenge the pollutant concentration monitors and CO_2 or O_2 monitors once with each calibration gas. Record the monitor response from the data acquisition and handling system. Using Equation A-5 of this appendix, determine the calibration error at each concentration once each day (at approximately 24-hour intervals) for 7 consecutive days according to the procedures given in this section. The results of a 7-day calibration error test are acceptable for monitor or monitoring system certification, recertification or diagnostic testing if none of these daily calibration error test results exceed the applicable performance specifications in section 3.1 of this appendix. The status of emission data from a gas monitor prior to and during a 7-day calibration error test period shall be determined as follows:

App. A § 6.3.1(a) (a) For initial certification, data from the monitor are considered invalid until all certification tests, including the 7-day calibration error test, have been successfully completed, unless the conditional data validation procedures in § 75.20(b)(3) are used. When the procedures in § 75.20(b)(3) are followed, the words "initial certification" apply instead of "recertification," and complete all of the initial certification tests by the applicable deadline in § 75.4, rather than within the time periods specified in § 75.20(b)(3)(iv) for the individual tests.

App. A § 6.3.1(b) (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).

App. A § 6.3.2 6.3.2 Flow Monitor 7-day Calibration Error Test

Flow monitors installed on peaking units (as defined in § 72.2 of this chapter) are exempted from the 7-day calibration error test requirements of this part. In all other cases, perform the 7-day calibration error test of a flow monitor, when required for certification, recertification, or diagnostic testing, according to the following procedures. Introduce the reference signal corresponding to the values specified in section 2.2.2.1 of this appendix to the probe tip (or equivalent), or to the transducer. During the 7-day certification test period, conduct the calibration error test while the unit is operating once each unit operating day (as close to 24-hour intervals as practicable). In the event that unit outages occur after the commencement of the test, the 7 consecutive operating days need not be 7 consecutive calendar days. Record the flow monitor responses by means of the data acquisition and handling system. Calculate the calibration error using Equation A-6 of this appendix. Do not perform any corrective maintenance, repair, or replacement upon the flow monitor during the 7-day test period other than that required in the quality assurance/quality control plan required by appendix B of 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:

App. A § 6.3.2(a) (a) For initial certification, data from the monitor are considered invalid until all certification tests, including the 7-day calibration error test, have been successfully completed, unless the conditional data validation procedures in § 75.20(b)(3) are used. When the procedures in § 75.20(b)(3) are followed, the words "initial certification" apply instead of "recertification," and complete all of the initial certification tests by the applicable deadline in § 75.4, rather than within the time periods specified in § 75.20(b)(3)(iv) for the individual tests.

App. A § 6.3.2(b) (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).

App. A § 6.3.3 6.3.3

For gas or flow monitors installed on peaking units, the exemption from performing the 7-day calibration error test applies as long as the unit continues to meet the definition of a peaking unit in § 72.2 of this chapter. However, if at the end of a particular calendar year or ozone season, it is

determined that peaking unit status has been lost, the owner or operator shall perform a diagnostic 7-day calibration error test of each monitor installed on the unit, by no later than December 31 of the following calendar year.

App. A § 6.4

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.) Prior to January 1, 2009, ~~F~~for the NO_x-diluent continuous emission monitoring system test~~ and SO_2-diluent continuous emission monitoring system test~~, either record and report the longer cycle time of the two component analyzers as the system cycle time or record the cycle time for each component analyzer separately (as applicable). On and after January 1, 2009, record the cycle time for each component analyzer separately. For time-shared systems, ~~this procedure must be done at all~~ perform the cycle time tests at each probe location~~s~~ 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.~~ at each monitoring location, ~~R~~report the sum of the ~~longest~~ cycle time observed at ~~each of the probe~~ that monitoring location~~s~~ 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 location~~s 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:

App. A § 6.4(a)

(a) For initial certification, data from the monitor are considered invalid until all certification tests, including the cycle time test, have been successfully completed, unless the conditional data validation procedures in § 75.20(b)(3) are used. When the procedures in § 75.20(b)(3) are followed, the words "initial certification" apply instead of "recertification," and complete all of the initial certification tests by the applicable deadline in § 75.4, rather than within the time periods specified in § 75.20(b)(3)(iv) for the individual tests.

App. A § 6.4(b)

(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).

App. A § 6.5

6.5 Relative Accuracy and Bias Tests (General Procedures)

Perform the required relative accuracy test audits (RATAs) as follows for each CO_2 emissions concentration monitor (including O_2 monitors used to determine CO_2 emissions concentration), each SO_2 pollutant concentration monitor, each NO_x concentration monitoring system used to determine NO_x mass emissions, each flow monitor, each NO_x-diluent CEMS, each

O_2 or CO_2 diluent monitor used to calculate heat input, each Hg concentration monitoring system, each sorbent trap monitoring system, and each moisture monitoring system. For NO_x concentration monitoring systems used to determine NO_x mass emissions, as defined in § 75.71(a)(2), use the same general RATA procedures as for SO_2 pollutant concentration monitors; however, use the reference methods for NO_x concentration specified in section 6.5.10 of this appendix:

App. A § 6.5(a) (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 a normal primary or backup fuel for that unit (for some units, more than one type of fuel may be considered normal, e.g., a unit that combusts gas or oil on a seasonal basis). For units that co-fire fuels as the predominant mode of operation, perform the RATAs while co-firing. For Hg monitoring systems, perform the RATAs while the unit is combusting coal. When relative accuracy test audits are performed on continuous emission monitoring systems installed on bypass stacks/ducts, use the fuel normally combusted by the unit (or units, if more than one unit exhausts into the flue) when emissions exhaust through the bypass stack/ducts.

App. A § 6.5(b) (b) Perform each RATA at the load (or operating) level(s) specified in section 6.5.1 or 6.5.2 of this appendix or in section 2.3.1.3 of appendix B to this part, as applicable.

App. A § 6.5(c) (c) For monitoring systems with dual ranges, perform the relative accuracy test on the range normally used for measuring emissions. For units with add-on SO_2 or NO_x controls or add-on Hg controls that operate continuously rather than seasonally, or for units that need a dual range to record high concentration "spikes" during startup conditions, the low range is considered normal. However, for some dual span units (e.g., for units that use fuel switching or for which the emission controls are operated seasonally), provided that both monitor ranges are connected to a common probe and sample interface, either of the two measurement ranges may be considered normal; in such cases, perform the RATA on the range that is in use at the time of the scheduled test. If the low and high measurement ranges are connected to separate sample probes and interfaces, RATA testing on both ranges is required.

App. A § 6.5(d) (d) Record monitor or monitoring system output from the data acquisition and handling system.

App. A § 6.5(e) (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.

App. A § 6.5(f) (f) The status of emission data from the CEMS prior to and during the RATA test period shall be determined as follows:

(1) For the initial certification of a CEMS, data from the monitoring system are considered invalid until all certification tests, including the RATA, have been successfully completed, unless the conditional data validation procedures in § 75.20(b)(3) are used. When the procedures in § 75.20(b)(3) are followed, the words "initial certification" apply instead of "recertification," and complete all of the initial certification tests by the applicable deadline in § 75.4, rather than within the time periods specified in § 75.20(b)(3)(iv) for the individual tests.

(2) For the routine quality assurance RATAs required by section 2.3.1 of appendix B to this part, use the data validation procedures in section 2.3.2 of appendix B to this part.

(3) For recertification RATAs, use the data validation procedures in § 75.20(b)(3).

(4) For quality assurance RATAs of non-redundant backup monitoring systems, use the data validation procedures in §§ 75.20(d)(2)(v) and (vi).

(5) For RATAs performed during and after the expiration of a grace period, use the data validation procedures in sections 2.3.2 and 2.3.3, respectively, of appendix B to this part.

(6) For all other RATAs, use the data validation procedures in section 2.3.2 of appendix B to this part.

App. A § 6.5(g) (g) For each SO_2 or CO_2 pollutant concentration monitor, each flow monitor, each CO_2 or O_2 diluent monitor used to determine heat input, each NO_x concentration monitoring system used to determine NO_x mass emissions, as defined in § 75.71(a)(2), each moisture monitoring system, each

NO_x-diluent CEMS, each Hg concentration monitoring system, and each sorbent trap 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_2, O_2, or moisture monitors), test for bias and determine the appropriate bias adjustment factor, in accordance with sections 7.6.4 and 7.6.5 of this appendix, using the data from the relative accuracy test audits.

App. A § 6.5.1

6.5.1 Gas Monitoring System RATAs (Special Considerations)

(a) Perform the required relative accuracy test audits for each SO_2 or CO_2 pollutant concentration monitor, each CO_2 or O_2 diluent monitor used to determine heat input, each NO_x-diluent CEMS, each NO_x concentration monitoring system used to determine NO_x mass emissions, as defined in § 75.71(a)(2), each Hg concentration monitoring system, and each sorbent trap monitoring system, at the normal load level or normal operating level for the unit (or combined units, if common stack), as defined in section 6.5.2.1 of this appendix. If two load levels or operating levels have been designated as normal, the RATAs may be done at either load level.

(b) For the initial certification of a gas or Hg 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.

App. A § 6.5.2

6.5.2 Flow Monitor RATAs (Special Considerations)

(a) Except as otherwise provided in paragraph (b) or (e) of this section,, perform relative accuracy test audits for the initial certification of each flow monitor at three different exhaust gas velocities (low, mid, and high), corresponding to three different load levels or operating levels within the range of operation, as defined in section 6.5.2.1 of this appendix. For a common stack/duct, the three different exhaust gas velocities may be obtained from frequently used unit/load or operating level combinations for the units exhausting to the common stack. Select the three exhaust gas velocities such that the audit points at adjacent load or operating levels (i.e., low and mid or mid and high), in megawatts (or in thousands of lb/hr of steam production or in ft/sec, as applicable), are separated by no less than 25.0 percent of the range of operation, as defined in section 6.5.2.1 of this appendix.

(b) For flow monitors on bypass stacks/ducts and peaking units, the flow monitor relative accuracy test audits for initial certification and recertification shall be single-load tests, performed at the normal load, as defined in section 6.5.2.1(d) of this appendix.

(c) Flow monitor recertification RATAs shall be done at three load level(s) (or three operating levels), unless otherwise specified in paragraph (b) or (e) of this section or unless otherwise specified or approved by the Administrator.

(d) The semiannual and annual quality assurance flow monitor RATAs required under appendix B to this part shall be done at the load level(s) (or operating levels) specified in section 2.3.1.3 of appendix B to this part.

(e) For flow monitors installed on units that do not produce electrical or thermal output, the flow RATAs for initial certification or recertification may be done at fewer than three operating levels, if:

(1) The owner or operator provides a technical justification in the hardcopy portion of the monitoring plan for the unit required under § 75.53 (e)(2), demonstrating that the unit operates at only one level or two levels during normal operation (excluding unit startup and shutdown). Appropriate documentation and data must be provided to support the claim of single-level or two-level operation; and

(2) The justification provided in paragraph (e)(1) of this section is deemed to be acceptable by the permitting authority.

App. A § 6.5.2.1

6.5.2.1 Range of Operation and Normal Load (or Operating) Level(s)

App. A § 6.5.2.1(a)

(a) The owner or operator shall determine the upper and lower boundaries of the "range of operation" as follows for each unit (or combination of units, for common stack configurations)~~ 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~~:

(1) For affected units that produce electrical output (in megawatts) or thermal output (in klb/hr of steam production or mmBtu/hr), the lower boundary of the range of operation of a unit shall be the minimum safe, stable 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 or mmBtu/hr of themal output; or

(2) For affected units that do not produce electrical or thermal output, the lower boundary of the range of operation shall be the minimum expected flue gas velocity (in ft/sec) during normal, stable operation of the unit. The upper boundary of the range of operation shall be the maximum potential flue gas velocity (in ft/sec) as defined in section 2.1.4.1 of this appendix. The minimum expected and maximum potential velocities may be derived from the results of reference method testing or by using Equation A-3a or A-3b (as applicable) in section 2.1.4.1 of this appendix. If Equation A-3a or A-3b is used to determine the minimum expected velocity, replace the word "maximum" to read "minimum" in the definitions of "MPV," "H_f," "% O_{2d}," and "% H_2O," and replace the word "minimum" with the word "maximum" in the definition of "CO_{2d}." Alternatively, 0.0 ft/sec may be used as the lower boundary of the range of operation.

App. A § 6.5.2.1(b)

(b) The operating levels for relative accuracy test audits shall, except for peaking units, be defined as follows: the "low" operating level shall be the first 30.0 percent of the range of operation; the "mid" operating level shall be the middle portion (> 30.0 percent, but ≤ 60.0 percent) of the range of operation; and the "high" operating level shall be the upper end (> 60.0 percent) of the range of operation. For example, if the upper and lower boundaries of the range of operation are 100 and 1100 megawatts, respectively, then the low, mid, and high operating levels would be 100 to 400 megawatts, 400 to 700 megawatts, and 700 to 1100 megawatts, respectively.

App. A § 6.5.2.1(c)

(c) Units that do not produce electrical or thermal output are exempted from the requirements of this paragraph, (c). The owner or operator shall identify, for each affected unit or common stack (except for peaking units and units using the low mass emissions (LME) excepted methodology under § 75.19), the "normal" load level or levels (low, mid or high), based on the operating history of the unit(s). To identify the normal load level(s), the owner or operator shall, at a minimum, determine the relative number of operating hours at each of the three load levels, low, mid and high over the past four representative operating quarters. The owner or operator shall determine, to the nearest 0.1 percent, the percentage of the time that each load level (low, mid, high) has been used during that time period. A summary of the data used for this determination and the calculated results shall be kept on-site in a format suitable for inspection. For new units or newly-affected units, the data analysis in this paragraph may be based on fewer than four quarters of data if fewer than four representative quarters of historical load data are available. Or, if no historical load data are available, the owner or operator may designate the normal load based on the expected or projected manner of operating the unit. However, in either case, once four quarters of representative data become available, the historical load analysis shall be repeated.

App. A § 6.5.2.1(d)

(d) *Determination of normal load (or operating level)*

(1) Based on the analysis of the historical load data described in paragraph (c) of this section, the owner or operator shall, for units that produce electrical or thermal output, designate the most frequently used load level as the normal load level for the unit (or combination of units, for common stacks). The owner or operator may also designate the second most frequently used load level as an additional normal load level for the unit or stack. For peaking units and LME units, normal load designations are unnecessary; the entire operating load range shall be considered normal. If the manner of operation of the unit changes significantly, such that the designated normal load(s) or the two most frequently used load levels change, the owner or operator shall repeat the historical load analysis and shall redesignate the normal load(s) and the two most frequently used load levels, as appropriate. A minimum of two representative quarters of historical load data are required to document that a change in the manner of unit operation has occurred. Update the electronic monitoring plan whenever the normal load level(s) and the two most frequently-used load levels are redesignated.

(2) For units that do not produce electrical or thermal output, the normal operating level(s)

shall be determined using sound engineering judgment, based on knowledge of the unit and operating experience with the industrial process.

App. A § 6.5.2.1(e)

(e) The owner or operator shall report the upper and lower boundaries of the range of operation for each unit (or combination of units, for common stacks), in units of megawatts or thousands of lb/hr or mmBtu/hr of steam production or ft/sec (as applicable), in the electronic ~~quarterly report~~ monitoring plan required under §75.~~64~~53 . Except for peaking units and LME 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.

App. A § 6.5.2.2

6.5.2.2 Multi-Load (or Multi-Level) Flow RATA Results

For each multi-load (or multi-level) flow RATA, calculate the flow monitor relative accuracy at each operating level. If a flow monitor relative accuracy test is failed or aborted due to a problem with the monitor on any level of a 2-level (or 3-level) relative accuracy test audit, the RATA must be repeated at that load (or operating) level. However, the entire 2-level (or 3-level) relative accuracy test audit does not have to be repeated unless the flow monitor polynomial coefficients or K-factor(s) are changed, in which case a 3-level RATA is required (or, a 2-level RATA, for units demonstrated to operate at only two levels, under section 6.5.2 (e) of this appendix).

App. A § 6.5.3

6.5.3 [Removed and Reserved]

App. A § 6.5.4

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.

App. A § 6.5.5

6.5.5 Reference Method Measurement Location

Select a location for reference method measurements that is (1) accessible; (2) in the same proximity as the monitor or monitoring system location; and (3) meets the requirements of Performance Specification 2 in appendix B of part 60 of this chapter for SO_2 and NO_x continuous emission monitoring systems, Performance Specification 3 in appendix B of part 60 of this chapter for CO_2 or O_2 monitors, or method 1 (or 1A) in appendix A of part 60 of this chapter for volumetric flow, except as otherwise indicated in this section or as approved by the Administrator.

App. A § 6.5.6

6.5.6 Reference Method Traverse Point Selection

Select traverse points that ensure acquisition of representative samples of pollutant and diluent concentrations, moisture content, temperature, and flue gas flow rate over the flue cross section. To achieve this, the reference method traverse points shall meet the requirements of section 8.1.3 of Performance Specification 2 ("PS No. 2") in appendix B to part 60 of this chapter (for SO_2, NO_x, and moisture monitoring system RATAs), Performance Specification 3 in appendix B to part 60 of this chapter (for O_2 and CO_2 monitor RATAs), Method 1 (or 1A) (for volumetric flow rate monitor RATAs), Method 3 (for molecular weight), and Method 4 (for moisture determination) in appendix A to part 60 of this chapter. The following alternative reference method traverse point locations are permitted for moisture and gas monitor RATAs.

App. A § 6.5.6(a)

(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.

App. A § 6.5.6(b)

(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

App. A § 6.5.6(b)(1) 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.

App. A § 6.5.6(b)(2) (2) At locations where section 8.1.3 of PS No. 2 allows the use of a short reference method measurement line (with three points located at 0.4, 1.2, and 2.0 meters from the stack wall), the owner or operator may use an alternative 3-point measurement line, locating the three points at 4.4, 14.6, and 29.6 percent of the way across the stack, in accordance with Method 1 in appendix A to part 60 of this chapter.

App. A § 6.5.6(b)(3) (3) At locations where stratification is likely to occur (e.g., following a wet scrubber or when dissimilar gas streams are combined), the short measurement line from section 8.1.3 of PS No. 2 (or the alternative line described in paragraph (b)(2) of this section) may be used in lieu of the prescribed "long" measurement line in ~~section 3.2~~ section 8.1.3 of PS No. 2, provided that the 12-point stratification test described in section 6.5.6.1 of this appendix is performed and passed one time at the location (according to the acceptance criteria of section 6.5.6.3(a) of this appendix) and provided that either the 12-point stratification test or the alternative (abbreviated) stratification test in section 6.5.6.2 of this appendix is performed and passed prior to each subsequent RATA at the location (according to the acceptance criteria of section 6.5.6.3(a) of this appendix).

App. A § 6.5.6(b)(4) (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).

App. A § 6.5.6(b)(5) (5) If Method 7E is used as the reference method for the RATA of a NO_x CEMS installed on a combustion turbine, the reference method measurements may be made at the sampling points specified in section 6.1.2 of Method 20 in appendix A to part 60 of this chapter.

App. A § 6.5.6(c) (c) For Hg monitoring systems, use the same traverse points that are used for the gas monitor RATAs.

App. A § 6.5.6.1 6.5.6.1 Stratification Test

(a) With the unit(s) operating under steady-state conditions at the normal load level (or normal operating level), as defined in section 6.5.2.1 of this appendix, use a traversing gas sampling probe to measure the pollutant (SO_2 or NO_x) and diluent (CO_2 or O_2) concentrations at a minimum of twelve (12) points, located according to Method 1 in appendix A to part 60 of this chapter.

(b) Use Methods 6C, 7E, and 3A in appendix A to part 60 of this chapter to make the measurements. Data from the reference method analyzers must be quality assured by performing analyzer calibration error and system bias checks before the series of measurements and by conducting system bias and calibration drift checks after the measurements, in accordance with the procedures of Methods 6C, 7E, and 3A.

(c) Measure for a minimum of 2 minutes at each traverse point. To the extent practicable, complete the traverse within a 2-hour period.

(d) If the load has remained constant (± 3.0 percent) during the traverse and if the reference method analyzers have passed all of the required quality assurance checks, proceed with the data analysis.

(e) Calculate the average NO_x, SO_2, and CO_2 (or O_2) concentrations at each of the individual traverse points. Then, calculate the arithmetic average NO_x, SO_2, and CO_2 (or O_2) concentrations for all traverse points.

App. A § 6.5.6.2 6.5.6.2 Alternative (Abbreviated) Stratification Test

(a) With the unit(s) operating under steady-state conditions at the normal load level (or normal operating level), as defined in section 6.5.2.1 of this appendix, use a traversing gas sampling probe to measure the pollutant (SO_2 or NO_x) and diluent (CO_2 or O_2) concentrations at three points. The points shall be located according to the specifications for the long measurement line in ~~section 3.2~~ section 8.1.3 of PS No. 2 (i.e., locate the points 16.7 percent, 50.0 percent, and 83.3 percent of the way across the stack). Alternatively, the concentration measurements may be made at six traverse points along a diameter. The six points shall be located in accordance with Method 1 in appendix A to part 60 of this chapter.

(b) Use Methods 6C, 7E, and 3A in appendix A to part 60 of this chapter to make the measurements. Data from the reference method analyzers must be quality assured by performing analyzer calibration error and system bias checks before the series of measurements and by conducting system bias and calibration drift checks after the measurements, in accordance with the procedures of Methods 6C, 7E, and 3A.

(c) Measure for a minimum of 2 minutes at each traverse point. To the extent practicable, complete the traverse within a 1-hour period.

(d) If the load has remained constant (± 3.0 percent) during the traverse and if the reference method analyzers have passed all of the required quality assurance checks, proceed with the data analysis.

(e) Calculate the average NO_x, SO_2, and CO_2 (or O_2) concentrations at each of the individual traverse points. Then, calculate the arithmetic average NO_x, SO_2, and CO_2 (or O_2) concentrations for all traverse points.

App. A § 6.5.6.3

6.5.6.3 Stratification Test Results and Acceptance Criteria

(a) For each pollutant or diluent gas, the short reference method measurement line described in section 8.1.3 of PS No. 2 may be used in lieu of the long measurement line prescribed in ~~section 3.2~~ section 8.1.3 of PS No. 2 if the results of a stratification test, conducted in accordance with section 6.5.6.1 or 6.5.6.2 of this appendix (as appropriate; see section 6.5.6(b)(3) of this appendix), show that the concentration at each individual traverse point differs by no more than ± 10.0 percent from the arithmetic average concentration for all traverse points. The results are also acceptable if the concentration at each individual traverse point differs by no more than ± 5 ppm or ± 0.5 percent CO_2 (or O_2) from the arithmetic average concentration for all traverse points.

(b) For each pollutant or diluent gas, a single reference method measurement point, located at least 1.0 meter from the stack wall and situated along one of the measurement lines used for the stratification test, may be used for that pollutant or diluent gas if the results of a stratification test, conducted in accordance with section 6.5.6.1 of this appendix, show that the concentration at each individual traverse point differs by no more than ± 5.0 percent from the arithmetic average concentration for all traverse points. The results are also acceptable if the concentration at each individual traverse point differs by no more than ± 3 ppm or ± 0.3 percent CO_2 (or O_2) from the arithmetic average concentration for all traverse points.

(c) The owner or operator shall keep the results of all stratification tests on-site, in a format suitable for inspection, as part of the supplementary RATA records required under § 75.59(a)(7).

App. A § 6.5.7

6.5.7 Sampling Strategy

App. A § 6.5.7(a)

(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_2 or O_2 monitor, flow monitor, and SO_2, Hg, or NO_x CEMS measurements. The minimum acceptable time for a gas monitoring system RATA run or for a moisture monitoring system RATA run is 21 minutes. For each run of a gas monitoring system RATA, all necessary pollutant concentration measurements, diluent concentration measurements, and moisture measurements (if applicable) must, to the extent practicable, be made within a 60-minute period. For NO_x-diluent monitoring system RATAs, the pollutant and diluent concentration measurements must be made simultaneously. For flow monitor RATAs, the minimum time per run shall be 5 minutes. Flow rate reference method measurements may be made either sequentially from port to port or simultaneously at two or more sample ports. The velocity measurement probe may be moved from traverse point to traverse point either manually or automatically. If, during a flow RATA, significant pulsations in the reference method readings are observed, be sure to allow enough measurement time at each traverse point to obtain an accurate average reading when a manual readout method is used (e.g., a "sight-weighted" average from a manometer). Also, allow sufficient measurement time to ensure that stable temperature readings are obtained at each traverse point, particularly at the first measurement point at each sample port, when a probe is moved sequentially from port-to-port. A minimum of one set of auxiliary measurements for stack gas molecular weight determination (i.e., diluent gas data and moisture data) is required for every clock hour of a flow RATA or for every three test runs (whichever is less restrictive). Alternatively, moisture measurements for molecular weight determination may be performed before and after a series of flow RATA runs at a particular load level (low, mid, or high), provided that the time interval between the two moisture measurements does not exceed three hours. If this option is selected, the results of the two moisture determinations shall be averaged arithmetically and applied to all RATA runs in the series. Successive flow RATA runs may be

performed without waiting in-between runs. If an O_2 diluent monitor is used as a CO_2 continuous emission monitoring system, perform a CO_2 system RATA (i.e., measure CO_2, rather than O_2, with the 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 § 75.59(a)(5)(vii). Whenever the coefficient, K factor or algorithm is changed, a RATA of the moisture monitoring system is required. For the RATA of a Hg CEMS using the Ontario Hydro Method, or for the RATA of a sorbent trap system (irrespective of the reference method used), the time per run must be long enough to collect a sufficient mass of Hg to analyze. For the RATA of a sorbent trap monitoring system, use the same-size trap and the same type of sorbent material that is used for daily operation of the monitoring system. Spike the third section of each sorbent trap with elemental Hg, as described in section 7.1.2 of appendix K to this part. Install a new pair of sorbent traps prior to each test run. For each run, the sorbent trap data shall be validated according to the quality assurance criteria in section 8 of appendix K to this part.

App. A § 6.5.7(b)

(b) To properly correlate individual SO_2, HG, or NO_x CEMS 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).

App. A § 6.5.8

6.5.8 Correlation of Reference Method and Continuous Emission Monitoring System

Confirm that the monitor or monitoring system and reference method test results are on consistent moisture, pressure, temperature, and diluent concentration basis (e.g., since the flow monitor measures flow rate on a wet basis, method 2 test results must also be on a wet basis). Compare flow-monitor and reference method results on a scfh basis. Also, consider the response times of the pollutant concentration monitor, the continuous emission monitoring system, and the flow monitoring system to ensure comparison of simultaneous measurements.

For each relative accuracy test audit run, compare the measurements obtained from the monitor or continuous emission monitoring system (in ppm, percent CO_2, lb/mmBtu, or other units) against the corresponding reference method values. Tabulate the paired data in a table such as the one shown in Figure 2.

App. A § 6.5.9

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.

App. A § 6.5.10

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_2 or CO_2; Method 4 for moisture; Methods 6, 6A, or 6C for SO_2; Methods 7, 7A, 7C, 7D, or 7E for NO_x, excluding the exceptions ~~in section 5.1.2~~ of Method 7E identified in § 75.22(a)(5)~~.~~; and either the Ontario Hydro Method, Method 29 in appendix A-8 to part 60 of this chapter, or an approved instrumental method for Hg (see § 75.22). ~~When using Method 7E for measuring NO_x concentration, total NO_x, both NO and NO_2, must be measured. Notwithstanding these requirements, Method 20 may be used as the reference method for relative accuracy test audits of NO_x monitoring systems installed on combustion turbines.~~

App. A § 7 **7. Calculations**

App. A § 7.1 *7.1 Linearity Check*

Analyze the linearity data for pollutant concentration and CO_2 or O_2 monitors as follows. Calculate the percentage error in linearity based upon the reference value at the low-level, mid-level, and high-level concentrations specified in section 6.2 of this appendix. Perform this calculation once during the certification test. Use the following equation to calculate the error in linearity for each reference value.

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

(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.

App. A § 7.2 *7.2 Calibration Error*

App. A § 7.2.1 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.
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.

App. A § 7.2.2 7.2.2 Flow Monitor Calibration Error

For each reference value, calculate the percentage calibration error based upon span using the following equation:

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

(Eq. A-6)
where:
CE = Calibration error as a percentage of the 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.

App. A § 7.3 *7.3 Relative Accuracy for SO_2 and CO_2 Emissions Concentration Monitors, O_2 Monitors, NO_x Concentration Monitoring Systems, Hg Monitoring Systems, and Flow Monitors*

Analyze the relative accuracy test audit data from the reference method tests for SO_2 and CO_2 emissions concentration monitors, CO_2 or O_2 monitors used only for heat input rate determination,

NO_x concentration monitoring systems used to determine NO_x mass emissions under subpart H of this part, Hg monitoring systems used to determine Hg mass emissions under subpart I of this part, and flow monitors using the following procedures. Summarize the results on a data sheet. An example is shown in Figure 2. Calculate the mean of the monitor or monitoring system measurement values. Calculate the mean of the reference method values. Using data from the automated data acquisition and handling system, calculate the arithmetic differences between the reference method and monitor measurement data sets. Then calculate the arithmetic mean of the difference, the standard deviation, the confidence coefficient, and the monitor or monitoring system relative accuracy using the following procedures and equations.

App. A § 7.3.1 7.3.1 Arithmetic Mean

Calculate the arithmetic mean of the differences, $\bar{d}$, 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_i.
d_i = The difference between a reference method value and the corresponding continuous emission monitoring system value (RM_i-CEM_i) at a given point in time i.

App. A § 7.3.2 7.3.2 Standard Deviation

Calculate the standard deviation, S_d, of a data set as follows:

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

(Eq. A-8)

App. A § 7.3.3 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,
$t_{0.025}$ = t value (see table 7-1).

TABLE 7-1 -- T-VALUES

n-1	$t_{0.025}$	n-1	$t_{0.025}$	n-1	$t_{0.025}$
1	12.706	12	2.179	23	2.069
2	4.303	13	2.160	24	2.064
3	3.182	14	2.145	25	2.060
4	2.776	15	2.131	26	2.056
5	2.571	16	2.120	27	2.052
6	2.447	17	2.110	28	2.048
7	2.365	18	2.101	29	2.045
8	2.306	19	2.093	30	2.042
9	2.262	20	2.086	40	2.021
10	2.228	21	2.080	60	2.000
11	2.201	22	2.074	>60	1.960

App. A § 7.3.4 7.3.4 Relative Accuracy

Calculate the relative accuracy of a data set using the following equation.

$$RA = \frac{|\bar{d}| + |cc|}{\overline{RM}} x\,100$$

(Eq. A-10)
where,
$\underline{RM}$ = Arithmetic mean of the reference method values.
$|\underline{d}|$ = 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.

App. A § 7.4 *7.4 Relative Accuracy for NO_x-diluent Continuous Emission Monitoring Systems*

Analyze the relative accuracy test audit data from the reference method tests for NO_x-diluent continuous emissions monitoring system as follows.

App. A § 7.4.1 7.4.1 Data Preparation

If C_{NOX}, the NO_x concentration, is in ppm, multiply it by 1.194×10^{-7} (lb/dscf)/ppm to convert it to units of lb/dscf. If C_{NOX} is in mg/dscm, multiply it by 6.24×10^{-8} (lb/dscf)/(mg/dscm) to convert it to lb/dscf. Then, use the diluent (O_2 or CO_2) reference method results for the run and the appropriate F or F_c factor from table 1 in appendix F of this part to convert C_{NOX} from lb/dscf to lb/mmBtu units. Use the equations and procedure in section 3 of appendix F to this part, as appropriate.

App. A § 7.4.2 7.4.2 NO_x Emission Rate

For each test run in a data set, calculate the average NO_x emission rate (in lb/mmBtu), by means of the data acquisition and handling system, during the time period of the test run. Tabulate the results as shown in example Figure 4.

App. A § 7.4.3 7.4.3 Relative Accuracy

Use the equations and procedures in section 7.3 above to calculate the relative accuracy for the NO_x continuous emission monitoring system. In using Equation A-7, "d" is, for each run, the difference between the NO_x emission rate values (in lb/mmBtu) obtained from the reference method data and the NO_x continuous emission monitoring system.

App. A § 7.5 *7.5 Relative Accuracy for Combined SO_2/Flow [Reserved]*

App. A § 7.6 *7.6 Bias Test and Adjustment Factor*

Test the following relative accuracy test audit data sets for bias: SO_2 pollutant concentration monitors; flow monitors; NO_x concentration monitoring systems used to determine NO_x mass emissions, as defined in § 75.71(a)(2); NO_x-diluent CEMS, Hg concentration monitoring systems, and sorbent trap monitoring systems, using the procedures outlined in sections 7.6.1 through 7.6.5 of this appendix. For multiple-load flow RATAs, perform a bias test at each load level designated as normal under section 6.5.2.1 of this appendix.

App. A § 7.6.1 7.6.1 Arithmetic Mean

Calculate the arithmetic mean of the difference, $\underline{d}$, of the data set using Equation A-7 of this appendix. To calculate bias for an SO_2 or NO_x pollutant concentration monitor, "d" is, for each paired data point, the difference between the SO_2 or NO_x concentration value (in ppm) obtained from the reference method and the monitor. To calculate bias for a flow monitor, "d" is, for each paired data point, the difference between the flow rate values (in scfh) obtained from the reference method and the monitor. To calculate bias for a NO_x-diluent continuous emission monitoring system, "d" is, for each paired data point, the difference between the NO_x emission rate values (in lb/mmBtu) obtained from the reference method and the monitoring system. To calculate bias for a Hg monitoring system when using the Ontario Hydro Method or Method 29 in appendix A-8 to part 60 of this chapter, "d" is, for each data point, the difference between the average Hg concentration value (in $\mu g/m^3$) from the paired Ontario Hydro or Method 29 sampling trains and the concentration measured by the monitoring system. For sorbent trap monitoring systems, use the average Hg concentration measured by the paired traps in the calculation of "d".

App. A § 7.6.2 7.6.2 Standard Deviation

Calculate the standard deviation, S_d, of the data set using Equation A-8.

App. A § 7.6.3 7.6.3 Confidence Coefficient

Calculate the confidence coefficient, cc, of the data set using Equation A-9.

App. A § 7.6.4 7.6.4 Bias Test

If, for the relative accuracy test audit data set being tested, the mean difference, $\bar{d}$, is less than or equal to the absolute value of the confidence coefficient, $|\ cc\ |$, the monitor or monitoring system has passed the bias test. If the mean difference, $\bar{d}$, is greater than the absolute value of the confidence coefficient, $|\ cc\ |$, the monitor or monitoring system has failed to meet the bias test requirement.

App. A § 7.6.5 7.6.5 Bias Adjustment

App. A § 7.6.5(a) (a) If the monitor or monitoring system fails to meet the bias test requirement, adjust the value obtained from the monitor using the following equation:

$$CEM_i^{Adjusted} = CEM_i^{Monitor} \ x \ BAF$$

(Eq. A-11)

Where:
$CEM_i^{Monitor}$ = Data (measurement) provided by the monitor at time i.
$CEM_i^{Adjusted}$ = Data value, adjusted for bias, at time i.
BAF = Bias adjustment factor, defined by:

$$BAF = 1 + \frac{\bar{d}}{CEM_{avg}}$$

(Eq. A-12)
Where:
BAF = Bias adjustment factor, calculated to the nearest thousandth.
$\bar{d}$ = Arithmetic mean of the difference obtained during the failed bias test using Equation A-7.
CEM_{avg} = Mean of the data values provided by the monitor during the failed bias test.

App. A § 7.6.5(b)

(b) For single-load RATAs of SO_2 pollutant concentration monitors, NO_x concentration monitoring systems, NO_x-diluent monitoring systems, Hg concentration monitoring systems, and sorbent trap monitoring systems, and for the single-load flow RATAs required or allowed under section 6.5.2 of this appendix and sections 2.3.1.3(b) and 2.3.1.3(c) of appendix B to this part, the appropriate BAF is determined directly from the RATA results at normal load, using Equation A-12. Notwithstanding, when a NO_x concentration CEMS or an SO_2 CEMS or a NO_x-diluent CEMS installed on a low-emitting affected unit (i.e., average SO_2 or NO_x concentration during the RATA < 250 ppm or average NO_x emission rate < 0.200 lb/mmBtu) meets the normal 10.0 percent relative accuracy specification (as calculated using Equation A-10) or the alternate relative accuracy specification in section 3.3 of this appendix for low-emitters, but fails the bias test, the BAF may either be determined using Equation A-12, or a default BAF of 1.111 may be used. Similarly, for Hg concentration and sorbent trap monitoring systems, where the average Hg concentration during the RATA is < 5.0 µg/dscm, if the monitoring system meets the normal or the alternative relative accuracy specification in section 3.3.8 of this appendix but fails the bias test, the owner or operator may either use the bias adjustment factor (BAF) calculated from Equation A–12 or may use a default BAF of 1.250 for reporting purposes under this part.

App. A § 7.6.5(c)

(c) For 2-load or 3-load flow RATAs, when only one load level (low, mid or high) has been designated as normal under section 6.5.2.1 of this appendix and the bias test is passed at the normal load level, apply a BAF of 1.000 to the subsequent flow rate data. If the bias test is failed at the normal load level, use Equation A-12 to calculate the normal load BAF and then perform an additional bias test at the second most frequently-used load level, as determined under section 6.5.2.1 of this appendix. If the bias test is passed at this second load level, apply the normal load BAF to the subsequent flow rate data. If the bias test is failed at this second load level, use Equation A-12 to calculate the BAF at the second load level and apply the higher of the two BAFs (either from the normal load level or from the second load level) to the subsequent flow rate data.

App. A § 7.6.5(d)

(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.

App. A § 7.6.5(e)

(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.

App. A § 7.6.5(f) (f) Use the bias-adjusted values in computing substitution values in the missing data procedure, as specified in subpart D of this part, and in reporting the concentration of SO_2 or Hg, the flow rate, the average NO_x emission rate, the unit heat input, and the calculated mass emissions of SO_2 and CO_2 during the quarter and calendar year, as specified in subpart G of this part. In addition, when using a NO_x concentration monitoring system and a flow monitor to calculate NO_x mass emissions under subpart H of this part, or when using a Hg concentration or sorbent trap monitoring system and a flow monitor to calculate Hg mass emissions under subpart I of this part, use bias-adjusted values for NO_x (or Hg) concentration and flow rate in the mass emission calculations and use bias-adjusted NO_x (or Hg) concentrations to compute the appropriate substitution values for NO_x (or Hg) concentration in the missing data routines under subpart D of this part.

App. A § 7.6.5(g) (g) For units that do not produce electrical or thermal output, the provisions of paragraphs (a) through (f) of this section apply, except that the expressions, "single-load", "2-load", "3-load" and "load level" shall be replaced, respectively, with the terms, "single-level", "2-level", "3-level", and "operating level".

App. A § 7.7 *7.7 Reference Flow-to-Load Ratio or Gross Heat Rate*

App. A § 7.7(a) (a) Except as provided in section 7.8 of this appendix, the owner or operator shall determine R_{ref}, the reference value of the ratio of flow rate to unit load, each time that a passing flow RATA is performed at a load level designated as normal in section 6.5.2.1 of this appendix. The owner or operator shall report the current value of R_{ref} in the electronic quarterly report required under § 75.64 and shall also report the completion date of the associated RATA. If two load levels have been designated as normal under section 6.5.2.1 of this appendix, the owner or operator shall determine a separate R_{ref} value for each of the normal load levels. The reference flow-to-load ratio shall be calculated as follows:

$$R_{ref} = \frac{Q_{ref}}{L_{avg}} x\, 10^{-5}$$

(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, or scfh/(mmBtu/hr of steam output).

Q_{ref} = Average stack gas volumetric flow rate measured by the reference method during the normal-load RATA, scfh.

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

App. A § 7.7(b) (b) In Equation A-13, for a common stack, determine L_{avg} by summing, for each RATA run, the operating loads of all units discharging through the common stack, and then taking the arithmetic average of the summed loads. For a unit that discharges its emissions through multiple stacks, either determine a single value of Q_{ref} for the unit or a separate value of Q_{ref} for each stack. In the former case, calculate Q_{ref} by summing, for each RATA run, the volumetric flow rates through the individual stacks and then taking the arithmetic average of the summed RATA run flow rates. In the latter case, calculate the value of Q_{ref} for each stack by taking the arithmetic average, for all RATA runs, of the flow rates through the stack. For a unit with a multiple stack discharge configuration consisting of a main stack and a bypass stack (e.g., a unit with a wet SO_2 scrubber), determine Q_{ref} separately for each stack at the time of the normal load flow RATA. Round off the value of R_{ref} to two decimal places.

App. A § 7.7(c) (c) In addition to determining R_{ref} or as an alternative to determining R_{ref}, a reference value of the gross heat rate (GHR) may be determined. In order to use this option, quality assured diluent gas (CO_2 or O_2) must be available for each hour of the most recent normal-load flow RATA. The reference value of the GHR shall be determined as follows:

$$(GHR)_{ref} = \frac{(Heat\ Input)_{avg}}{L_{avg}} \ x\ 1000$$

(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, or Btu heat input/mmBtu steam output.

$(\text{Heat Input})_{avg}$ = Average hourly heat input during the normal-load flow RATA, as determined using the applicable equation in appendix F to this part, mmBtu/hr. For multiple stack configurations, if the reference GHR value is determined separately for each stack, use the hourly heat input measured at each stack. If the reference GHR is determined at the unit level, sum the hourly heat inputs measured at the individual stacks.

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

App. A § 7.7(d)

(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 (i.e., the arithmetic average of the diluent gas concentrations for all clock hours in which a RATA run was performed).

App. A § 7.8

7.8 Flow-to-Load Test Exemptions

(a) 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 and section 2.2.5 of appendix B to this part. The petition must include sufficient information and data to demonstrate that a flow-to-load or gross heat rate evaluation is infeasible for the complex stack configuration.

(b) Units that do not produce electrical output (in megawatts) or thermal output (in klb of steam per hour) are exempted from the flow-to-load ratio test requirements of section 7.7 of this appendix and section 2.2.5 of appendix B to this part.

FIGURES FOR APPENDIX A OF PART 75
FIGURE 1. TO APPENDIX A--LINEARITY ERROR DETERMINATION

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

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

Run No.	Date and time	SO_2 (ppm[c])			Date and time	CO_2 (Pollutant) (ppm[c])		
		RM[a]	M[b]	Diff		RM[a]	M[b]	Diff
1								
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
Arithmetic Mean Difference (Eq. A-7). Confidence Coefficient (Eq. A-9). Relative Accuracy (Eq. A-10).								

[a] RM means "reference method data."
[b] M means "monitor data."
[c] Make sure the RM and M data are on a consistent basis, either wet or dry.

FIGURE 3. TO APPENDIX A--RELATIVE ACCURACY DETERMINATION (FLOW MONITORS)

Run No.	Date and time	Flow rate (Low) (scf/hr)*			Date and time	Flow rate (Normal) (scf/hr)*			Date and time	Flow rate (High) (scf/hr)*		
		RM	M	Diff		RM	M	Diff		RM	M	Diff
1.....												
2.....												
3.....												
4.....												
5.....												
6.....												
7.....												
8.....												
9.....												
10												
11												
12												
Arithmetic Mean Difference (Eq. A-7). Confidence Coefficient (Eq. A-9). Relative Accuracy (Eq. A-10).												

* Make sure the RM and M data are on a consistent basis, either wet or dry.

FIGURE 4. TO APPENDIX A--RELATIVE ACCURACY DETERMINATION (NO_X/DILUENT COMBINED SYSTEM)

Run No.	Date and time	Reference method data		NO_x system (lb/mmBtu)		
		NO_x( )[a]	O_2/CO_2%	RM	M	Difference
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
Arithmetic Mean Difference (Eq. A-7). Confidence Coefficient (Eq. A-9). Relative Accuracy (Eq. A-10).						

[a] Specify units; ppm, lb/dscf, mg/dscm.

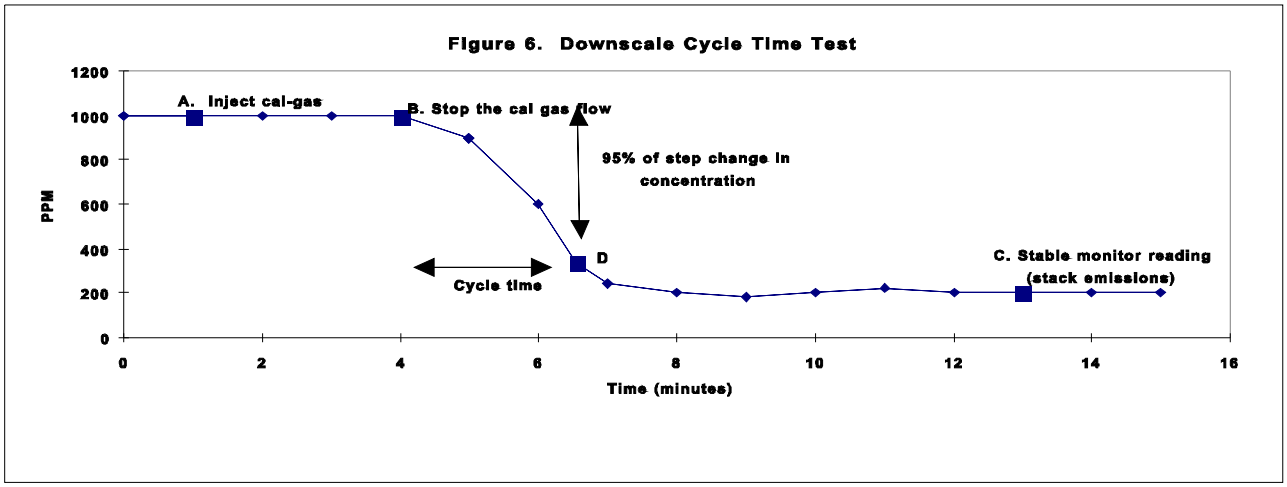
FIGURE 5. TO APPENDIX A--Cycle Time

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 reading: ppm/% (circle one)
Elapsed time: seconds

Component cycle time = _____ seconds
System cycle time = seconds



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.

Appendix B to Part 75 -- Quality Assurance and Quality Control Procedures

App. B § 1

1. Quality Assurance/Quality Control Program

Develop and implement a quality assurance/quality control (QA/QC) program for the continuous emission monitoring systems, excepted monitoring systems approved under appendix D or E to this part, and alternative monitoring systems under subpart E of this part, and their components. At a minimum, include in each QA/QC program a written plan that describes in detail (or that refers to separate documents containing) complete, step-by-step procedures and operations for each of the following activities. Upon request from regulatory authorities, the source shall make all procedures, maintenance records, and ancillary supporting documentation from the manufacturer (e.g., software coefficients and troubleshooting diagrams) available for review during an audit. Electronic storage of the information in the QA/QC plan is permissible, provided that the information can be made available in hardcopy upon request during an audit.

App. B § 1.1

1.1 Requirements for All Monitoring Systems

App. B § 1.1.1

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.

App. B § 1.1.2

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.

App. B § 1.1.3

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.

App. B § 1.1.4 1.1.4 The requirements in section 6.1.2 of appendix A to this part shall be met by any Air Emissions Testing Body (AETB) performing the semiannual/annual RATAs described in section 2.3 of this appendix and the periodic Hg emission tests described in §§ 75.81(c)(1) and 75.81(d)(4)(iii).

App. B § 1.2 *1.2 Specific Requirements for Continuous Emissions Monitoring Systems*

App. B § 1.2.1 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.

App. B § 1.2.2 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.

App. B § 1.2.3 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.

App. B § 1.2.4 1.2.4 Parametric Monitoring for Units with Add-on Emission Controls

The owner or operator shall keep a written (or electronic) record including a list of operating parameters for the add-on SO_2 or NO_x emission controls, including parameters in § 75.55(b) or § 75.58(b), as applicable, and the range of each operating parameter that indicates the add-on emission controls are operating properly. The owner or operator shall keep a written (or electronic) record of the parametric monitoring data during each SO_2 or NO_x missing data period.

App. B § 1.3 *1.3 Specific Requirements for Excepted Systems Approved under Appendices D and E*

App. B § 1.3.1 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 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).

App. B § 1.3.2 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.

App. B § 1.3.3 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.

App. B § 1.3.4 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.

App. B § 1.3.5 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).

App. B § 1.3.6 1.3.6 Appendix E Monitoring System Quality Assurance Information

Identify the recommended range of quality assurance- and quality control-related operating parameters. Keep records of these operating parameters for each hour of unit operation (i.e., fuel combustion). Keep a written record of the procedures used to perform NO_x emission rate testing. Keep a copy of all data and results from the initial and from the most recent NO_x emission rate testing, including the values of quality assurance parameters specified in section 2.3 of appendix E to this part.

App. B § 1.4 *1.4 Requirements for Alternative Systems Approved under Subpart E*

App. B § 1.4.1 1.4.1 Daily Quality Assurance Tests

Explain how the daily assessment procedures specific to the alternative monitoring system are to be performed.

App. B § 1.4.2 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.

App. B § 1.4.3 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.

App. B § 1.5 *1.5 Requirements for Sorbent Trap Monitoring Systems*

App. B § 1.5.1 1.5.1 Sorbent Trap Identification and Tracking

Include procedures for inscribing or otherwise permanently marking a unique identification number on each sorbent trap, for tracking purposes. Keep records of the ID of the monitoring system in which each sorbent trap is used, and the dates and hours of each Hg

collection period.

App. B § 1.5.2 1.5.2 Monitoring System Integrity and Data Quality

Explain the procedures used to perform the leak checks when a sorbent trap is placed in service and removed from service. Also explain the other QA procedures used to ensure system integrity and data quality, including, but not limited to, dry gas meter calibrations, verification of moisture removal, and ensuring air-tight pump operation. In addition, the QA plan must include the data acceptance and quality control criteria in section 8 of appendix K to this part.

App. B § 1.5.3 1.5.3 Hg Analysis

Explain the chain of custody employed in packing, transporting, and analyzing the sorbent traps (see sections 7.2.8 and 7.2.9 in appendix K to this part). Keep records of all Hg analyses. The analyses shall be performed in accordance with the procedures described in section 10 of appendix K to this part.

App. B § 1.5.4 1.5.4 Laboratory Certification

The QA Plan shall include documentation that the laboratory performing the analyses on the carbon sorbent traps is certified by the International Organization for Standardization (ISO) to have a proficiency that meets the requirements of ISO 17025. Alternatively, if the laboratory performs the spike recovery study described in section 10.3 of appendix K to this part and repeats that procedure annually, ISO certification is not required.

App. B § 1.5.5 1.5.5 Data Collection Period

State, and provide the rationale for, the minimum acceptable data collection period (e.g., one day, one week, etc.) for the size of sorbent trap selected for the monitoring. Include in the discussion such factors as the Hg concentration in the stack gas, the capacity of the sorbent trap, and the minimum mass of Hg required for the analysis.

App. B § 1.5.6 1.5.6 Relative Accuracy Test Audit Procedures

Keep records of the procedures and details peculiar to the sorbent trap monitoring systems that are to be followed for relative accuracy test audits, such as sampling and analysis methods.

App. B § 2 **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.

App. B § 2.1 *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.

App. B § 2.1.1 2.1.1 Calibration Error Test

Except as provided in section 2.1.1.2 of this appendix, perform the daily calibration error test of each gas monitoring system (including moisture monitoring systems consisting of wet- and dry-basis O_2 analyzers) ~~and each Hg monitoring system~~ according to the procedures in section 6.3.1 of appendix A to this part, and perform the daily calibration error test of each flow monitoring system according to the procedure in section 6.3.2 of appendix A to this part. When

two measurement ranges (low and high) are required for a particular parameter, perform sufficient calibration error tests on each range to validate the data recorded on that range, according to the criteria in section 2.1.5 of this appendix. ~~For Hg monitors, the daily assessments may be made using either elemental Hg standards or a NIST-traceable source of oxidized Hg.~~

~~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.~~

App. B § 2.1.1.1

2.1.1.1 On-line Daily Calibration Error Tests. Except as provided in section 2.1.1.2 of this appendix, all daily calibration error tests must be performed while the unit is in operation at normal, stable conditions (i.e. "on-line").

App. B § 2.1.1.2

2.1.1.2 Off-line Daily Calibration Error Tests. Daily calibrations may be performed while the unit is not operating (i.e., "off-line") and may be used to validate data for a monitoring system that meets the following conditions:

(1) An initial demonstration test of the monitoring system is successfully completed and the results are reported in the quarterly report required under § 75.64 of this part. The initial demonstration test, hereafter called the "off-line calibration demonstration", consists of an off-line calibration error test followed by an on-line calibration error test. Both the off-line and on-line portions of the off-line calibration demonstration must meet the calibration error performance specification in section 3.1 of appendix A of this part. Upon completion of the off-line portion of the demonstration, the zero and upscale monitor responses may be adjusted, but only toward the true values of the calibration gases or reference signals used to perform the test and only in accordance with the routine calibration adjustment procedures specified in the quality control program required under section 1 of appendix B to this part. Once these adjustments are made, no further adjustments may be made to the monitoring system until after completion of the on-line portion of the off-line calibration demonstration. Within 26 clock hours of the completion hour of the off-line portion of the demonstration, the monitoring system must successfully complete the first attempted calibration error test, i.e., the on-line portion of the demonstration.

(2) For each monitoring system that has passed the off-line calibration demonstration, off-line calibration error tests may be used on a limited basis to validate data, in accordance with paragraph (2) in section 2.1.5.1 of this appendix. ~~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.~~

App. B § 2.1.2

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.

App. B § 2.1.3

2.1.3 Additional Calibration Error Tests and Calibration Adjustments

App. B § 2.1.3(a)

(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.

App. B § 2.1.3(b)

(b) Routine calibration adjustments of a monitor are permitted after any successful calibration error test. These routine adjustments shall be made so as to bring the monitor

readings as close as practicable to the known tag values of the calibration gases or to the actual value of the flow monitor reference signals. An additional calibration error test is required following routine calibration adjustments where the monitor's calibration has been physically adjusted (e.g., by turning a potentiometer) to verify that the adjustments have been made properly. An additional calibration error test is not required, however, if the routine calibration adjustments are made by means of a mathematical algorithm programmed into the data acquisition and handling system. The EPA recommends that routine calibration adjustments be made, at a minimum, whenever the daily calibration error exceeds the limits of the applicable performance specification in appendix A to this part for the pollutant concentration monitor, CO_2 or O_2 monitor, or flow monitor.

App. B § 2.1.3(c)

(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.

App. B § 2.1.4

2.1.4 Data Validation

App. B § 2.1.4(a)

(a) An out-of-control period occurs when the calibration error of an SO_2 or NO_x pollutant concentration monitor exceeds 5.0 percent of the span value, when the calibration error of a CO_2 or O_2 monitor (including O_2 monitors used to measure CO_2 emissions or percent moisture) exceeds 1.0 percent O_2 or CO_2, or when the calibration error of a flow monitor or a moisture sensor exceeds 6.0 percent of the span value, which is twice the applicable specification of appendix A to this part. Notwithstanding, a differential pressure-type flow monitor for which the calibration error exceeds 6.0 percent of the span value shall not be considered out-of-control if |R- A|, the absolute value of the difference between the monitor response and the reference value in Equation A-6 of appendix A to this part, is < 0.02 inches of water. In addition, an SO_2 or NO_x monitor for which the calibration error exceeds 5.0 percent of the span value shall not be considered out-of-control if |R- A| in Equation A-6 does not exceed 5.0 ppm (for span values < 50 ppm), or if |R- A| does not exceed 10.0 ppm (for span values > 50 ppm, but < 200 ppm). For a Hg monitor, an out-of-control period occurs when the calibration error exceeds 5.0% of the span value. Notwithstanding, the Hg monitor shall not be considered out-of-control if |R−A| in Equation A−6 does not exceed 1.0 μg/scm. The out-of-control period begins upon failure of the calibration error test and ends upon completion of a successful calibration error test. Note, that if a failed calibration, corrective action, and successful calibration error test occur within the same hour, emission data for that hour recorded by the monitor after the successful calibration error test may be used for reporting purposes, provided that two or more valid readings are obtained as required by § 75.10. A NO_x-diluent CEMS is considered out-of-control if the calibration error of either component monitor exceeds twice the applicable performance specification in appendix A to this part. Emission data shall not be reported from an out-of-control monitor.

App. B § 2.1.4(b)

(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

App. B § 2.1.5

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.

App. B § 2.1.5.1

2.1.5.1 Data Invalidation with Respect to Daily Assessments. The following specific rules apply to the invalidation of data with respect to daily assessments:

(1) Data from a monitoring system are invalid, beginning with the first hour following the expiration of a 26-hour data validation period or beginning with the first hour following the expiration of an 8-hour start-up grace period (as provided under section 2.1.5.2 of this appendix), if the required subsequent daily assessment has not been conducted.

(2) For a monitor that has passed the off-line calibration demonstration, off-line calibration error tests may be used to validate data from the monitor for up to 26 consecutive unit or stack operating hours, after which data from the monitor become invalid until an on-line calibration error test of the monitor is passed. Once the required on-line calibration error test has been passed, another 26 operating hour cycle of data validation using off-line calibration error tests may begin. Each off-line calibration error test that is used for data validation has a prospective data validation window of 26 clock hours, as described in section 2.1.5 of this appendix. If the sequence of consecutive operating hours validated by off-line calibrations is broken before reaching the 26th consecutive unit or stack operating hour, data from the monitor become invalid and an on-line calibration error test must be passed to re-establish the quality-assured data status. The sequence is considered broken when a unit or stack operating hour is not contained within the 26 clock hour data validation window of a passed off-line calibration error test.

(3) For units with two measurement ranges (low and high) for a particular parameter, when separate analyzers are used for the low and high ranges, a failed or expired calibration on one of the ranges does not affect the quality-assured data status on the other range. For a dual-range analyzer (i.e., a single analyzer with two measurement scales), a failed calibration error test on either the low or high scale results in an out-of-control period for the monitor. Data from the monitor remain invalid until corrective actions are taken and "hands-off" calibration error tests have been passed on both ranges. However, if the most recent calibration error test on the high scale has expired, while the low scale is up-to-date on its calibration error test requirements (or vice-versa), the expired calibration error test does not affect the quality-assured status of the data recorded on the other scale. ~~(2) 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.~~

App. B § 2.1.5.2

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.

App. B § 2.1.6

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.

App. B § 2.2 *2.2 Quarterly Assessments*

For each primary and redundant backup monitor or monitoring system, perform the following quarterly assessments. This requirement is applies as of the calendar quarter following the calendar quarter in which the monitor or continuous emission monitoring system is provisionally certified.

App. B § 2.2.1 2.2.1 Linearity Check

Unless a particular monitor (or monitoring range) is exempted under this paragraph or under section 6.2 of appendix A to this part, perform a linearity check, in accordance with the procedures in section 6.2 of appendix A to this part, for each primary and redundant backup SO_2, Hg and NO_x pollutant concentration monitor and each primary and redundant backup CO_2 or O_2 monitor (including O_2 monitors used to measure CO_2 emissions or to continuously monitor moisture) at least once during each QA operating quarter, as defined in § 72.2 of this chapter. For Hg monitors, perform the linearity checks using elemental Hg standards. Alternatively, you may perform 3-level system integrity checks at the same three calibration gas levels (i.e., low, mid, and high), using a NIST-traceable source of oxidized Hg. If you choose this option, the performance specification in section 3.2(c)(3) of appendix A to this part must be met at each gas level. 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.

App. B § 2.2.2 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 thirty days apart, to the extent practicable. If a leak check is failed, follow the applicable data validation procedures in section 2.2.3 (g) of this appendix.

App. B § 2.2.3 2.2.3 Data Validation

App. B § 2.2.3(a) (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.

App. B § 2.2.3(b) (b) Each required linearity check shall be done according to paragraph (b)(1), (b)(2) or (b)(3) of this section:

(1) The linearity check may be done "cold," i.e., with no corrective maintenance, repair, calibration adjustments, re-linearization or reprogramming of the monitor prior to the test.

(2) The linearity check may be done after performing only the routine or non-routine calibration adjustments described in section 2.1.3 of this appendix at the various calibration gas levels (zero, low, mid or high), but no other corrective maintenance, repair, re-linearization or reprogramming of the monitor. Trial gas injection runs may be performed after the calibration adjustments and additional adjustments within the allowable limits in section 2.1.3 of this appendix may be made prior to the linearity check, as necessary, to optimize the performance of the monitor. The trial gas injections need not be reported, provided that they meet the

specification for trial gas injections in § 75.20(b)(3)(vii)(E)(*1*). However, if, for any trial injection, the specification in § 75.20(b)(3)(vii)(E)(*1*) is not met, the trial injection shall be counted as an aborted linearity check.

(3) The linearity check may be done after repair, corrective maintenance or reprogramming of the monitor. In this case, the monitor shall be considered out-of-control from the hour in which the repair, corrective maintenance or reprogramming is commenced until the linearity check has been passed. Alternatively, the data validation procedures and associated timelines in §§ 75.20(b)(3)(ii) through (ix) may be followed upon completion of the necessary repair, corrective maintenance, or reprogramming. If the procedures in § 75.20(b)(3) are used, the words "quality assurance" apply rather than the word "recertification."

App. B § 2.2.3(c)

(c) Once a linearity check has been commenced, the test shall be done hands-off. That is, no adjustments of the monitor are permitted during the linearity test period, other than the routine calibration adjustments following daily calibration error tests, as described in section 2.1.3 of this appendix. If a routine daily calibration error test is performed and passed just prior to a linearity test (or during a linearity test period) and a mathematical correction factor is automatically applied by the DAHS, the correction factor shall be applied to all subsequent data recorded by the monitor, including the linearity test data.

App. B § 2.2.3(d)

(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.

App. B § 2.2.3(e)

(e) An out-of-control period occurs when a linearity test is failed (i.e., when the error in linearity at any of the three concentrations in the quarterly linearity check (or any of the six concentrations, when both ranges of a single analyzer with a dual range are tested) exceeds the applicable specification in section 3.2 of appendix A to this part) or when a linearity test is aborted due to a problem with the monitor or monitoring system. For a NO_x-diluent continuous emission monitoring system, the system is considered out-of-control if either of the component monitors exceeds the applicable specification in section 3.2 of appendix A to this part or if the linearity test of either component is aborted due to a problem with the monitor. The out-of-control period begins with the hour of the failed or aborted linearity check and ends with the hour of completion of a satisfactory linearity check following corrective action and/or monitor repair, unless the option in paragraph (b)(3) of this section to use the data validation procedures and associated timelines in § 75.20(b)(3)(ii) through (ix) has been selected, in which case the beginning and end of the out-of-control period shall be determined in accordance with §§ 75.20(b)(3)(vii)(A) and (B). For a dual-range analyzer, "hands-off" linearity checks must be passed on both measurement scales to end the out-of-control period. Note that a monitor shall not be considered out-of-control when a linearity test is aborted for a reason unrelated to the monitor's performance (e.g., a forced unit outage).

App. B § 2.2.3(f)

(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.

App. B § 2.2.3(g)

(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.

App. B § 2.2.3(h)

(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.

App. B § 2.2.4

2.2.4 Linearity and Leak Check Grace Period

(a) When a required linearity test or flow monitor leak check has not been completed by the end of the QA operating quarter in which it is due or if, due to infrequent operation of a unit or infrequent use of a required high range of a monitor or monitoring system, four successive calendar quarters have elapsed after the quarter in which a linearity check of a monitor or monitoring system (or range) was last performed without a subsequent linearity test having been done, the owner or operator has a grace period of 168 consecutive unit operating hours, as defined in § 72.2 of this chapter (or, for monitors installed on common stacks or bypass stacks, 168 consecutive stack operating hours, as defined in § 72.2 of this chapter) in which to perform a linearity test or leak check of that monitor or monitoring system (or range). The grace period begins with the first unit or stack operating hour following the calendar quarter in which the linearity test was due. Data validation during a linearity or leak check grace period shall be done in accordance with the applicable provisions in section 2.2.3 of this appendix.

(b) If, at the end of the 168 unit (or stack) operating hour grace period, the required linearity test or leak check has not been completed, data from the monitoring system (or range) shall be invalid, beginning with the first unit operating hour following the expiration of the grace period. Data from the monitoring system (or range) remain invalid until the hour of completion of a subsequent successful hands-off linearity test or leak check of the monitor or monitoring system (or range). Note that when a linearity test or a leak check is conducted within a grace period for the purpose of satisfying the linearity test or leak check requirement from a previous QA operating quarter, the results of that linearity test or leak check may only be used to meet the linearity check or leak check requirement of the previous quarter, not the quarter in which the missed linearity test or leak check is completed.

App. B § 2.2.5

2.2.5 Flow-to-Load Ratio or Gross Heat Rate Evaluation

App. B § 2.2.5(a)

(a) *Applicability and methodology*. Unless exempted from the flow-to-load ratio test under section 7.8 of appendix A to this part, the owner or operator shall, for each flow rate monitoring system installed on each unit, common stack or multiple stack, evaluate the flow-to-load ratio quarterly, i.e., for each QA operating quarter (as defined in § 72.2 of this chapter). At the end of each QA operating quarter, the owner or operator shall use Equation B-1 to calculate the flow-to-load ratio for every hour during the quarter in which: the unit (or combination of units, for a common stack) operated within + 10.0 percent of L_{avg}, the average load during the most recent normal-load flow RATA; and a quality assured hourly average flow rate was obtained with a certified flow rate monitor. Alternatively, for the reasons stated in paragraphs (c)(1) through (c)(6) of this section, the owner or operator may exclude from the data analysis certain hours within + 10.0 percent of L_{avg} and may calculate R_h values for only the remaining hours.

$$R_h = \frac{Q_h}{L_h} x\, 10^{-5}$$

(Eq. B-1)

Where:

R_h = Hourly value of the flow-to-load ratio, scfh/megawatts, ~~or~~ scfh/1000 lb/hr of steam, or scfh/(mmBtu/hr thermal output).

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

L_h = Hourly unit load, megawatts, ~~or~~ 1000 lb/hr of steam, or mmBtu/hr thermal output; must be within + 10.0 percent of L_{avg} during the most recent normal-load flow RATA.

App. B § 2.2.5(a)(1) (1) In Equation B-1, the owner or operator may use either bias-adjusted flow rates or unadjusted flow rates, provided that all of the ratios are calculated the same way. For a common stack, L_h shall be the sum of the hourly operating loads of all units that discharge through the stack. For a unit that discharges its emissions through multiple stacks or that monitors its emissions in multiple breechings, Q_h will be either the combined hourly volumetric flow rate for all of the stacks or ducts (if the test is done on a unit basis) or the hourly flow rate through each stack individually (if the test is performed separately for each stack). For a unit with a multiple stack discharge configuration consisting of a main stack and a bypass stack, each of which has a certified flow monitor (e.g., a unit with a wet SO_2 scrubber), calculate the hourly flow-to-load ratios separately for each stack. Round off each value of R_h to two decimal places.

App. B § 2.2.5(a)(2) (2) Alternatively, the owner or operator may calculate the hourly gross heat rates (GHR) in lieu of the hourly flow-to-load ratios. The hourly GHR shall be determined only for those hours in which quality assured flow rate data and diluent gas (CO_2 or O_2) concentration data are both available from a certified monitor or monitoring system or reference method. If this option is selected, calculate each hourly GHR value as follows:

$$(GHR)_h = \frac{(Heat\ Input)_h}{L_h} x\ 1000$$

(Eq. B-1a)

Where:

$(GHR)_h$ = Hourly value of the gross heat rate, Btu/kwh, ~~or~~ Btu/lb steam load, or Btu heat input/mmBtu thermal output.

$(Heat\ Input)_h$ = Hourly heat input, as determined from the quality assured flow rate and diluent data, using the applicable equation in appendix F to this part, mmBtu/hr.

L_h = Hourly unit load, megawatts, ~~or~~ 1000 lb/hr of steam, or mmBtu/hr thermal output; must be within + 10.0 percent of L_{avg} during the most recent normal-load flow RATA.

App. B § 2.2.5(a)(3) (3) In Equation B-1a, the owner or operator may either use bias-adjusted flow rates or unadjusted flow rates in the calculation of $(Heat\ Input)_h$, provided that all of the heat input rate values are determined in the same manner.

App. B § 2.2.5(a)(4) (4) The owner or operator shall evaluate the calculated hourly flow-to-load ratios (or gross heat rates) as follows. A separate data analysis shall be performed for each primary and each redundant backup flow rate monitor used to record and report data during the quarter. Each analysis shall be based on a minimum of 168 acceptable recorded hourly average flow rates (i.e., at loads within ± 10 percent of L_{avg}). When two RATA load levels are designated as normal, the analysis shall be performed at the higher load level, unless there are fewer than 168 acceptable data points available at that load level, in which case the analysis shall be performed at the lower load level. If, for a particular flow monitor, fewer than 168 acceptable hourly flow-to-load ratios (or GHR values) are available at any of the load levels designated as normal, a flow-to-load (or GHR) evaluation is not required for that monitor for that calendar quarter.

App. B § 2.2.5(a)(5) (5) For each flow monitor, use Equation B-2 in this appendix to calculate E_h, the absolute percentage difference between each hourly R_h value and R_{ref}, the reference value of the flow-to-load ratio, as determined in accordance with section 7.7 of appendix A to this part. Note that R_{ref} shall always be based upon the most recent normal-load RATA, even if that RATA was performed in the calendar quarter being evaluated.

$$E_h = \frac{|R_{ref} - R_h|}{R_{ref}} x\ 100$$

(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 + 10.0 percent of L_{avg}.

R_{ref} = The reference value of the flow-to-load ratio from the most recent normal-load flow RATA, determined in accordance with section 7.7 of appendix A to this part.

App. B § 2.2.5(a)(6)

(6) Equation B-2 shall be used in a consistent manner. That is, use R_{ref} and R_h if the flow-to-load ratio is being evaluated, and use $(GHR)_{ref}$ and $(GHR)_h$ if the gross heat rate is being evaluated. Finally, calculate E_f, the arithmetic average of all of the hourly E_h values. The owner or operator shall report the results of each quarterly flow-to-load (or gross heat rate) evaluation, as determined from Equation B-2, in the electronic quarterly report required under § 75.64.

App. B § 2.2.5(b)

(b) *Acceptable results.* The results of a quarterly flow-to-load (or gross heat rate) evaluation are acceptable, and no further action is required, if the calculated value of E_f is less than or equal to:

(1) 15.0 percent, if L_{avg} for the most recent normal-load flow RATA is > 60 megawatts (or > 500 klb/hr of steam) and if unadjusted flow rates were used in the calculations; or

(2) 10.0 percent, if L_{avg} for the most recent normal-load flow RATA is > 60 megawatts (or > 500 klb/hr of steam) and if bias-adjusted flow rates were used in the calculations; or

(3) 20.0 percent, if L_{avg} for the most recent normal-load flow RATA is < 60 megawatts (or < 500 klb/hr of steam) and if unadjusted flow rates were used in the calculations; or

(4) 15.0 percent, if L_{avg} for the most recent normal-load flow RATA is < 60 megawatts (or < 500 klb/hr of steam) and if bias-adjusted flow rates were used in the calculations. If E_f is above these limits, the owner or operator shall either: implement Option 1 in section 2.2.5.1 of this appendix; perform a RATA in accordance with Option 2 in section 2.2.5.2 of this appendix; or (if applicable) re-examine the hourly data used for the flow-to-load or GHR analysis and recalculate E_f, after excluding all non-representative hourly flow rates, as provided in paragraph (c) of this section.

App. B § 2.2.5(c)

(c) *Recalculation of E_f.* If the owner or operator did not exclude any hours within + 10 percent of L_{avg} from the original data analysis and chooses to recalculate E_f, the flow rates for the following hours are considered non-representative and may be excluded from the data analysis:

(1) Any hour in which the type of fuel combusted was different from the fuel burned during the most recent normal-load RATA. For purposes of this determination, the type of fuel is different if the fuel is in a different state of matter (i.e., solid, liquid, or gas) than is the fuel burned during the RATA or if the fuel is a different classification of coal (e.g., bituminous versus sub-bituminous). Also, for units that co-fire different types of fuels, if the reference RATA was done while co-firing, then hours in which a single fuel was combusted may be excluded from the data analysis as different fuel hours (and vice-versa for co-fired hours, if the reference RATA was done while combusting only one type of fuel);

(2) For a unit that is equipped with an SO_2 scrubber and which always discharges its flue gases to the atmosphere through a single stack, any hour in which the SO_2 scrubber was bypassed;

(3) Any hour in which "ramping" occurred, i.e., the hourly load differed by more than + 15.0 percent from the load during the preceding hour or the subsequent hour;

(4) For a unit with a multiple stack discharge configuration consisting of a main stack and a bypass stack, any hour in which the flue gases were discharged through both stacks;

(5) If a normal-load flow RATA was performed and passed during the quarter being analyzed, any hour prior to completion of that RATA; and

(6) If a problem with the accuracy of the flow monitor was discovered during the quarter and was corrected (as evidenced by passing the abbreviated flow-to-load test in section 2.2.5.3 of this appendix), any hour prior to completion of the abbreviated flow-to-load test.

(7) After identifying and excluding all non-representative hourly data in accordance with paragraphs (c)(1) through (6) of this section, the owner or operator may analyze the remaining data a second time. At least 168 representative hourly ratios or GHR values must be available to perform the analysis; otherwise, the flow-to-load (or GHR) analysis is not required for that

monitor for that calendar quarter.

(8) If, after re-analyzing the data, E_f meets the applicable limit in paragraph (b)(1), (b)(2), (b)(3), or (b)(4) of this section, no further action is required. If, however, E_f is still above the applicable limit, data from the monitor shall be declared out-of-control, beginning with the first unit operating hour following the quarter in which E_f exceeded the applicable limit. Alternatively, if a probationary calibration error test is performed and passed according to § 75.20(b)(3)(ii), data from the monitor may be declared conditionally valid following the quarter in which E_f exceeded the applicable limit. The owner or operator shall then either implement Option 1 in section 2.2.5.1 of this appendix or Option 2 in section 2.2.5.2 of this appendix.

App. B § 2.2.5.1

2.2.5.1 Option 1

Within 14 unit operating days of the end of the calendar quarter for which the E_f value is above the applicable limit, investigate and troubleshoot the applicable flow monitor(s). Evaluate the results of each investigation as follows:

(a) If the investigation fails to uncover a problem with the flow monitor, a RATA shall be performed in accordance with Option 2 in section 2.2.5.2 of this appendix.

(b) If a problem with the flow monitor is identified through the investigation (including the need to re-linearize the monitor by changing the polynomial coefficients or K factor(s)), data from the monitor are considered invalid back to the first unit operating hour after the end of the calendar quarter for which E_f was above the applicable limit. If the option to use conditional data validation was selected under section 2.2.5(c)(8) of this appendix, all conditionally valid data shall be invalidated, back to the first unit operating hour after the end of the calendar quarter for which E_f was above the applicable limit. Corrective actions shall be taken. All corrective actions (e.g., non-routine maintenance, repairs, major component replacements, re-linearization of the monitor, etc.) shall be documented in the operation and maintenance records for the monitor. The owner or operator then shall either complete the abbreviated flow-to-load test in section 2.2.5.3 of this appendix, or, if the corrective action taken has required relinearization of the flow monitor, shall perform a 3-load RATA. The conditional data validation procedures in § 75.20(b)(3) may be applied to the 3-load RATA.

App. B § 2.2.5.2

2.2.5.2 Option 2

Perform a single-load RATA (at a load designated as normal under section 6.5.2.1 of appendix A to this part) of each flow monitor for which E_f is outside of the applicable limit. If the RATA is passed hands-off, in accordance with section 2.3.2(c) of this appendix, no further action is required and the out-of-control period for the monitor ends at the date and hour of completion of a successful RATA, unless the option to use conditional data validation was selected under section 2.2.5(c)(8) of this appendix. In that case, all conditionally valid data from the monitor are considered to be quality-assured, back to the first unit operating hour following the end of the calendar quarter for which the E_f value was above the applicable limit. If the RATA is failed, all data from the monitor shall be invalidated, back to the first unit operating hour following the end of the calendar quarter for which the E_f value was above the applicable limit. Data from the monitor remain invalid until the required RATA has been passed. Alternatively, following a failed RATA and corrective actions, the conditional data validation procedures of § 75.20(b)(3) may be used until the RATA has been passed. If the corrective actions taken following the failed RATA included adjustment of the polynomial coefficients or K-factor(s) of the flow monitor, a 3-level RATA is required, except as otherwise specified in section 2.3.1.3 of this appendix.

App. B § 2.2.5.3

2.2.5.3 Abbreviated Flow-to-Load Test

App. B § 2.2.5.3(a)

(a) The following abbreviated flow-to-load test may be performed after any documented repair, component replacement, or other corrective maintenance to a flow monitor (except for changes affecting the linearity of the flow monitor, such as adjusting the flow monitor coefficients or K factor(s)) to demonstrate that the repair, replacement, or other maintenance has not significantly affected the monitor's ability to accurately measure the stack gas volumetric flow rate. Data from the monitoring system are considered invalid from the hour of commencement of the repair, replacement, or maintenance until either the hour in which the abbreviated flow-to-

load test is passed, or the hour in which a probationary calibration error test is passed following completion of the repair, replacement, or maintenance and any associated adjustments to the monitor. If the latter option is selected, the abbreviated flow-to-load test shall be completed within 168 unit operating hours of the probationary calibration error test (or, for peaking units, within 30 unit operating days, if that is less restrictive). Data from the monitor are considered to be conditionally valid (as defined in § 72.2 of this chapter), beginning with the hour of the probationary calibration error test.

App. B § 2.2.5.3(b) (b) Operate the unit(s) in such a way as to reproduce, as closely as practicable, the exact conditions at the time of the most recent normal-load flow RATA. To achieve this, it is recommended that the load be held constant to within + 10.0 percent of the average load during the RATA and that the diluent gas (CO_2 or O_2) concentration be maintained within + 0.5 percent CO_2 or O_2 of the average diluent concentration during the RATA. For common stacks, to the extent practicable, use the same combination of units and load levels that were used during the RATA. When the process parameters have been set, record a minimum of six and a maximum of 12 consecutive hourly average flow rates, using the flow monitor(s) for which E_f was outside the applicable limit. For peaking units, a minimum of three and a maximum of 12 consecutive hourly average flow rates are required. Also record the corresponding hourly load values and, if applicable, the hourly diluent gas concentrations. Calculate the flow-to-load ratio (or GHR) for each hour in the test hour period, using Equation B-1 or B-1a. Determine E_h for each hourly flow-to-load ratio (or GHR), using Equation B-2 of this appendix and then calculate E_f, the arithmetic average of the E_h values.

App. B § 2.2.5.3(c) (c) The results of the abbreviated flow-to-load test shall be considered acceptable, and no further action is required if the value of E_f does not exceed the applicable limit specified in section 2.2.5 of this appendix. All conditionally valid data recorded by the flow monitor shall be considered quality assured, beginning with the hour of the probationary calibration error test that preceded the abbreviated flow-to-load test (if applicable). However, if E_f is outside the applicable limit, all conditionally valid data recorded by the flow monitor (if applicable) shall be considered invalid back to the hour of the probationary calibration error test that preceded the abbreviated flow-to-load test, and a single-load RATA is required in accordance with section 2.2.5.2 of this appendix. If the flow monitor must be re-linearized, however, a 3-load RATA is required.

App. B § 2.3 *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.

App. B § 2.3.1 2.3.1 Relative Accuracy Test Audit (RATA)

App. B § 2.3.1.1 2.3.1.1 Standard RATA Frequencies

(a) Except for Hg monitoring systems and as otherwise specified in § 75.21(a)(6) or (a)(7) or in section 2.3.1.2 of this appendix, perform relative accuracy test audits semiannually, i.e., once every two successive QA operating quarters (as defined in § 72.2 of this chapter) for each primary and redundant backup SO_2 pollutant concentration monitor, flow monitor, CO_2 emissions concentration monitor (including O_2 monitors used to determine CO_2 emissions), CO_2 or O_2 diluent monitor used to determine heat input, moisture monitoring system, NO_x concentration monitoring system, NO_x-diluent CEMS, or SO_2-diluent continuous emission monitoring system. For each primary and redundant backup Hg concentration monitoring system and each sorbent trap monitoring system, RATAs shall be performed annually, i.e., once every four successive QA operating quarters (as defined in § 72.2 of this chapter). 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.

App. B § 2.3.1.2

2.3.1.2 Reduced RATA Frequencies

Relative accuracy test audits of primary and redundant backup SO_2 pollutant concentration monitors, CO_2 pollutant concentration monitors (including O_2 monitors used to determine CO_2 emissions), CO_2 or O_2 diluent monitors used to determine heat input, moisture monitoring systems, NO_x concentration monitoring systems, flow monitors, NO_x-diluent monitoring systems or SO_2-diluent monitoring systems may be performed annually (i.e., once every four successive QA operating quarters, rather than once every two successive QA operating quarters) if any of the following conditions are met for the specific monitoring system involved:

App. B § 2.3.1.2(a)

(a) The relative accuracy during the audit of an SO_2 or CO_2 pollutant concentration monitor (including an O_2 pollutant monitor used to measure CO_2 using the procedures in appendix F to this part), or of a CO_2 or O_2 diluent monitor used to determine heat input, or of a NO_x concentration monitoring system, or of a NO_x-diluent monitoring system, or of an SO_2-diluent continuous emissions monitoring system is $\leq$ 7.5 percent;

App. B § 2.3.1.2(b)

(b) [Removed and Reserved]

App. B § 2.3.1.2(c)

(c) The relative accuracy during the audit of a flow monitor is $\leq$ 7.5 percent at each operating level tested;

App. B § 2.3.1.2(d)

(d) For low flow ($\leq$10.0 fps, as measured by the reference method during the RATA) stacks/ducts, when the flow monitor fails to achieve a relative accuracy $\leq$ 7.5 percent during the audit, but the monitor mean value, calculated using Equation A-7 in appendix A to this part and converted back to an equivalent velocity in standard feet per second (fps), is within $\pm$ 1.5 fps of the reference method mean value, converted to an equivalent velocity in fps;

App. B § 2.3.1.2(e)

(e) For low SO_2 or NO_x emitting units (average SO_2 or NO_x reference method concentrations $\leq$ 250 ppm) during the RATA, when an SO_2 pollutant concentration monitor or NO_x 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;

App. B § 2.3.1.2(f)

(f) For units with low NO_x emission rates (average NO_x emission rate measured by the reference method during the RATA $\leq$ 0.200 lb/mmBtu), when a NO_x-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;

App. B § 2.3.1.2(g)

(g) [Removed and Reserved]

App. B § 2.3.1.2(h)

(h) For a CO_2 or O_2 monitor, when the mean difference between the reference method values from the RATA and the corresponding monitor values is within $\pm$ 0.7 percent CO_2 or O_2; and

App. B § 2.3.1.2(i) (i) When the relative accuracy of a continuous moisture monitoring system is ≤ 7.5 percent or when the mean difference between the reference method values from the RATA and the corresponding monitoring system values is within ± 1.0 percent H_2O.

App. B § 2.3.1.3 2.3.1.3 RATA Load (or Operating) Levels and Additional RATA Requirements

App. B § 2.3.1.3(a) (a) For SO_2 pollutant concentration monitors, CO_2 emissions concentration monitors (including O_2 monitors used to determine CO_2 emissions), CO_2 or O_2 diluent monitors used to determine heat input, NO_x concentration monitoring systems, Hg concentration monitoring systems, sorbent trap monitoring systems, moisture monitoring systems, and NO_x-diluent monitoring systems, the required semiannual or annual RATA tests shall be done at the load level (or operating level) designated as normal under section 6.5.2.1(d) of appendix A to this part. If two load levels (or operating levels) are designated as normal, the required RATA(s) may be done at either load level (or operating level).

App. B § 2.3.1.3(b) (b) For flow monitors installed on peaking units and bypass stacks, and for flow monitors that qualify to perform only single-level RATAs under section 6.5.2. (E) of appendix A to this part, all required semiannual or annual relative accuracy test audits shall be single-load (or single-level) audits at the normal load (or operating level), as defined in section 6.5.2.1(d) of appendix A to this part.

App. B § 2.3.1.3(c) (c) For all other flow monitors, the RATAs shall be performed as follows:

(1) An annual 2-load (or 2-level) flow RATA shall be done at the two most frequently used load levels (or operating levels), as determined under section 6.5.2.1(d) of appendix A to this part, or (if applicable) at the operating levels determined under section 6.5.2 (e) of appendix A to this part. Alternatively, a 3-load (or 3-level) flow RATA at the low, mid, and high load levels (or operating levels), as defined under section 6.5.2.1(b) of appendix A to this part, may be performed in lieu of the 2-load (or 2-level) annual RATA.

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

(3) A single-load (or single-level) annual flow RATA may be performed in lieu of the 2-load (or 2-level) RATA if the results of an historical load data analysis show that in the time period extending from the ending date of the last annual flow RATA to a date that is no more than 21 days prior to the date of the current annual flow RATA, the unit (or combination of units, for a common stack) has operated at a single load level (or operating level) (low, mid, or high), for > 85.0 percent of the time. Alternatively, a flow monitor may qualify for a single-load (or single-level) RATA if the 85.0 percent criterion is met in the time period extending from the beginning of the quarter in which the last annual flow RATA was performed through the end of the calendar quarter preceding the quarter of current annual flow RATA.

(4) A 3-load (or 3-level) RATA, at the low-, mid-, and high-load levels (or operating levels), as determined under section 6.5.2.1 of appendix A to this part, shall be performed at least once every ~~five~~ twenty consecutive calendar ~~years~~ quarters, except for flow monitors that are exempted from 3-load (or 3-level) RATA testing under section 6.5.2 (b) or 6.5.2 (e) of appendix A to this part.

(5) A 3-load (or 3-level) RATA is required whenever a flow monitor is re-linearized, i.e., when its polynomial coefficients or K factor(s) are changed, except for flow monitors that are exempted from 3-load (or 3-level) RATA testing under section 6.5.2 (b) or 6.5.2 (e) of appendix A to this part. For monitors so exempted under section 6.5.2 (b), a single-load flow RATA is required. For monitors so exempted under section 6.5.2 (e), either a single-level RATA or a 2-level RATA is required, depending on the number of operating levels documented in the monitoring plan for the unit.

(6) For all multi-level flow audits, the audit points at adjacent load levels or at adjacent operating levels (e.g., mid and high) shall be separated by no less than 25.0 percent of the "range of operation," as defined in section 6.5.2.1 of appendix A to this part.

App. B § 2.3.1.3(d) (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.

App. B § 2.3.1.4 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.

App. B § 2.3.2 2.3.2 Data Validation

App. B § 2.3.2(a) (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.

App. B § 2.3.2(b) (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."

App. B § 2.3.2(c) (c) Once a RATA is commenced, the test must be done hands-off. No adjustment of the monitor's calibration is permitted during the RATA test period, other than the routine calibration adjustments following daily calibration error tests, as described in section 2.1.3 of this appendix. If a routine daily calibration error test is performed and passed just prior to a RATA (or during a RATA test period) and a mathematical correction factor is automatically applied by the DAHS, the correction factor shall be applied to all subsequent data recorded by the monitor, including the RATA test data. For 2-level and 3-level flow monitor audits, no linearization or reprogramming of the monitor is permitted in between load levels.

App. B § 2.3.2(d) (d) For single-load (or single-level) RATAs, if a daily calibration error test is failed during a RATA test period, prior to completing the test, the RATA must be repeated. Data from the monitor are invalidated prospectively from the hour of the failed calibration error test until the hour of completion of a subsequent successful calibration error test. The subsequent RATA shall not be commenced until the monitor has successfully passed a calibration error test in accordance with section 2.1.3 of this appendix. For multiple-load (or multiple-level) flow RATAs, each load level (or operating level) is treated as a separate RATA (i.e., when a calibration error test is failed prior to completing the RATA at a particular load level (or operating level), only the RATA at that load level (or operating level) must be repeated; the results of any previously-passed

RATA(s) at the other load level(s) (or operating level(s)) are unaffected, unless re-linearization of the monitor is required to correct the problem that caused the calibration failure, in which case a subsequent 3-load (or 3-level) RATA is required), except as otherwise provided in section 2.3.1.3 (c)(5) of this appendix.

App. B § 2.3.2(e)

(e) For a RATA performed using the option in paragraph (b)(1) or (b)(2) of this section, if the RATA is failed (that is, if the relative accuracy exceeds the applicable specification in section 3.3 of appendix A to this part) or if the RATA is aborted prior to completion due to a problem with the CEMS, then the CEMS is out-of-control and all emission data from the CEMS are invalidated prospectively from the hour in which the RATA is failed or aborted. Data from the CEMS remain invalid until the hour of completion of a subsequent RATA that meets the applicable specification in section 3.3 of appendix A to this part. If the option in paragraph (b)(3) of this section to use the data validation procedures and associated timelines in §§ 75.20(b)(3)(ii) through(b)(3)(ix) has been selected, the beginning and end of the out-of-control period shall be determined in accordance with § 75.20(b)(3)(vii)(A) and (B). Note that when a RATA is aborted for a reason other than monitoring system malfunction (see paragraph (h) of this section), this does not trigger an out-of-control period for the monitoring system.

App. B § 2.3.2(f)

(f) For a 2-level or 3-level flow RATA, if, at any load level (or operating level), a RATA is failed or aborted due to a problem with the flow monitor, the RATA at that load level (or operating level) must be repeated. The flow monitor is considered out-of-control and data from the monitor are invalidated from the hour in which the test is failed or aborted and remain invalid until the passing of a RATA at the failed load level (or operating level), unless the option in paragraph (b)(3) of this section to use the data validation procedures and associated timelines in § 75.20(b)(3)(ii) through (b)(3)(ix) has been selected, in which case the beginning and end of the out-of-control period shall be determined in accordance with § 75.20(b)(3)(vii)(A) and (B). Flow RATA(s) that were previously passed at the other load level(s) (or operating level(s)) do not have to be repeated unless the flow monitor must be re-linearized following the failed or aborted test. If the flow monitor is re-linearized, a subsequent 3-load (or 3-level) RATA is required, except as otherwise provided in section 2.3.1.3 (c)(5) of this appendix.

App. B § 2.3.2(g)

(g) Data validation for failed RATAs for a CO_2 pollutant concentration monitor (or an O_2 monitor used to measure CO_2 emissions), a NO_x pollutant concentration monitor, and a NO_x-diluent monitoring system shall be done according to paragraphs (g)(1) and (g)(2) of this section:

(1) For a CO_2 pollutant concentration monitor (or an O_2 monitor used to measure CO_2 emissions) which also serves as the diluent component in a NOx-diluent monitoring system, if the CO_2 (or O_2) RATA is failed, then both the O_2 (or O_2) monitor and the associated NOx-diluent system are considered out-of-control, beginning with the hour of completion of the failed CO_2 (or O_2) monitor RATA, and continuing until the hour of completion of subsequent hands-off RATAs which demonstrate that both systems have met the applicable relative accuracy specifications in sections 3.3.2 and 3.3.3 of appendix A to this part, unless the option in paragraph (b)(3) of this section to use the data validation procedures and associated timelines in §§ 75.20(b)(3)(ii) through (b)(3)(ix) has been selected, in which case the beginning and end of the out-of-control period shall be determined in accordance with §§ 75.20(b)(3)(vii)(A) and (B).

(2) This paragraph (g)(2) applies only to a NO_x pollutant concentration monitor that serves both as the NO_x component of a NO_x concentration monitoring system (to measure NO_x mass emissions) and as the NO_x component in a NO_x-diluent monitoring system (to measure NO_x emission rate in lb/mmBtu). If the RATA of the NO_x concentration monitoring system is failed, then both the NO_x concentration monitoring system and the associated NO_x-diluent monitoring system are considered out-of-control, beginning with the hour of completion of the failed NO_x concentration RATA, and continuing until the hour of completion of subsequent hands-off RATAs which demonstrate that both systems have met the applicable relative accuracy specifications in sections 3.3.2 and 3.3.7 of appendix A to this part, unless the option in paragraph (b)(3) of this section to use the data validation procedures and associated timelines in §§ 75.20(b)(3)(ii) through (b)(3)(ix) has been selected, in which case the beginning and end of the out-of-control period shall be determined in accordance with §§ 75.20(b)(3)(vii)(A) and (B).

~~(g) For a CO_2 pollutant concentration monitor (or an O_2 monitor used to measure CO_2 emissions) which also serves as the diluent component in a NO_x diluent (or SO_2 diluent)~~

~~monitoring system, if the CO_2 (or O_2) RATA is failed, then both the CO_2 (or O_2) monitor and the associated NO_x-diluent (or SO_2-diluent) system are considered out-of-control, beginning with the hour of completion of the failed CO_2 (or O_2) monitor RATA, and continuing until the hour of completion of subsequent hands-off RATAs which demonstrate that both systems have met the applicable relative accuracy specifications in sections 3.3.2 and 3.3.3 of appendix A to this part, unless the option in paragraph (b)(3) of this section to use the data validation procedures and associated timelines in §§ 75.20(b)(3)(ii) through (b)(3)(ix) has been selected, in which case the beginning and end of the out-of-control period shall be determined in accordance with §§ 75.20(b)(3)(vii)(A) and (B).~~

App. B § 2.3.2(h) (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.

App. B § 2.3.2(i) (i) Each time that a hands-off RATA of an SO_2 pollutant concentration monitor, a NO_x-diluent monitoring system, a NO_x concentration monitoring system, a Hg concentration monitoring system, a sorbent trap monitoring system, or a flow monitor is passed, perform a bias test in accordance with section 7.6.4 of appendix A to this part. Apply the appropriate bias adjustment factor to the reported SO_2, Hg, NO_x, or flow rate data, in accordance with section 7.6.5 of appendix A to this part.

App. B § 2.3.2(j) (j) Failure of the bias test does not result in the monitoring system being out-of-control.

App. B § 2.3.3 2.3.3 RATA Grace Period

App. B § 2.3.3(a) (a) The owner or operator has a grace period of 720 consecutive unit operating hours, as defined in § 72.2 of this chapter (or, for CEMS installed on common stacks or bypass stacks, 720 consecutive stack operating hours, as defined in § 72.2 of this chapter), in which to complete the required RATA for a particular CEMS whenever:

(1) A required RATA has not been performed by the end of the QA operating quarter in which it is due; or

(2) ~~Five consecutive calendar years have elapsed without a~~ A required 3-load flow RATA has not been performed by the end of the calendar quarter in which it is due ~~having been conducted~~; or

(3) For a unit which is conditionally exempted under § 75.21(a)(7) from the SO_2 RATA requirements of this part, an SO_2 RATA has not been completed by the end of the calendar quarter in which the annual usage of fuel(s) with a sulfur content higher than very low sulfur fuel (as defined in § 72.2 of this chapter) exceeds 480 hours; or

(4) Eight successive calendar quarters have elapsed, following the quarter in which a RATA was last performed, without a subsequent RATA having been done, due either to infrequent operation of the unit(s) or frequent combustion of very low sulfur fuel, as defined in § 72.2 of this chapter (SO_2 monitors, only), or a combination of these factors.

App. B § 2.3.3(b) (b) Except for SO_2 monitoring system RATAs, the grace period shall begin with the first unit (or stack) operating hour following the calendar quarter in which the required RATA was due. For SO_2 monitor RATAs, the grace period shall begin with the first unit (or stack) operating hour in which fuel with a total sulfur content higher than that of very low sulfur fuel (as defined in § 72.2 of this chapter) is burned in the unit(s), following the quarter in which the required RATA is due. Data validation during a RATA grace period shall be done in accordance with the applicable provisions in section 2.3.2 of this appendix.

App. B § 2.3.3(c)

(c) If, at the end of the 720 unit (or stack) operating hour grace period, the RATA has not been completed, data from the monitoring system shall be invalid, beginning with the first unit operating hour following the expiration of the grace period. Data from the CEMS remain invalid until the hour of completion of a subsequent hands-off RATA. The deadline for the next test shall be either two QA operating quarters (if a semiannual RATA frequency is obtained) or four QA operating quarters (if an annual RATA frequency is obtained) after the quarter in which the RATA is completed, not to exceed eight calendar quarters.~~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 .~~

App. B § 2.3.3(d)

(d) When a RATA is done during a grace period in order to satisfy a RATA requirement from a previous quarter, the deadline for the next RATA shall determined as follows:

(1) If the grace period RATA qualifies for a reduced**,** (i.e., annual), RATA frequency the deadline for the next RATA shall be set at three QA operating quarters after the quarter in which the grace period test is completed.

(2) If the grace period RATA qualifies for the standard, (i.e., semiannual), RATA frequency the deadline for the next RATA shall be set at two QA operating quarters after the quarter in which the grace period test is completed.

(3) Notwithstanding these requirements**,** no more than eight successive calendar quarters shall elapse after the quarter in which the grace period test is completed, without a subsequent RATA having been conducted.

App. B § 2.3.4

2.3.4 Bias Adjustment Factor

Except as otherwise specified in section 7.6.5 of appendix A to this part, if an SO_2 pollutant concentration monitor, flow monitor, NO_x CEMS, NO_x concentration monitoring system used to calculate NO_x mass emissions, Hg concentration monitoring system, or sorbent trap monitoring system fails the bias test specified in section 7.6 of appendix A to this part, or the allowable alternative BAF specified in section 7.6.5(b) of appendix A of 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.

App. B § 2.4

2.4 Recertification, Quality Assurance, RATA Frequency and Bias Adjustment Factors (Special Considerations)

(a) When a significant change is made to a monitoring system such that recertification of the monitoring system is required in accordance with § 75.20(b), a recertification test (or tests) must be performed to ensure that the CEMS continues to generate valid data. In all recertifications, a RATA will be one of the required tests; for some recertifications, other tests will also be required. A recertification test may be used to satisfy the quality assurance test requirement of this appendix. For example, if, for a particular change made to a CEMS, one of the required recertification tests is a linearity check and the linearity check is successful, then, unless another such recertification event occurs in that same QA operating quarter, it would not be necessary to perform an additional linearity test of the CEMS in that quarter to meet the quality assurance requirement of section 2.2.1 of this appendix. For this reason, EPA recommends that owners or operators coordinate component replacements, system upgrades, and other events that may require recertification, to the extent practicable, with the periodic quality assurance testing required by this appendix. When a quality assurance test is done for the dual purpose of recertification and routine quality assurance, the applicable data validation procedures in § 75.20(b)(3) shall be followed.

(b) Except as provided in section 2.3.3 of this appendix, whenever a passing RATA of a gas monitor is performed, or a passing 2-load (or 2-level) RATA or a passing 3-load (or 3-level) RATA of a flow monitor is performed (irrespective of whether the RATA is done to satisfy a

recertification requirement or to meet the quality assurance requirements of this appendix, or both), the RATA frequency (semi-annual or annual) shall be established based upon the date and time of completion of the RATA and the relative accuracy percentage obtained. For 2-load (or 2-level) and 3-load (or 3-level) flow RATAs, use the highest percentage relative accuracy at any of the loads (or levels) to determine the RATA frequency. The results of a single-load (or single-level) flow RATA may be used to establish the RATA frequency when the single-load (or single-level) flow RATA is specifically required under section 2.3.1.3(b) of this appendix or when the single-load (or single-level) RATA is allowed under section 2.3.1.3(c) of this appendix for a unit that has operated at one load level (or operating level) for ≥ 85.0 percent of the time since the last annual flow RATA. No other single-load (or single-level) flow RATA may be used to establish an annual RATA frequency; however, a 2-load or 3-load (or a 2-level or 3-level) flow RATA may be performed at any time or in place of any required single-load (or single-level) RATA, in order to establish an annual RATA frequency.

App. B § 2.5 *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.

App. B § 2.6 *2.6 System Integrity Checks for Hg Monitors*

For each Hg concentration monitoring system (except for a Hg monitor that does not have a converter), perform a single-point system integrity check weekly, i.e., at least once every 168 unit or stack operating hours, using a NIST-traceable source of oxidized Hg. Perform this check using a mid- or high-level gas concentration, as defined in section 5.2 of appendix A to this part. The performance specifications in paragraph (3) of section 3.2~~(c)(3)~~ of appendix A to this part must be met, otherwise the monitoring system is considered out-of-control, from the hour of the failed check until a subsequent system integrity check is passed. If a required system integrity check is not performed and passed within 168 unit or stack operating hours of last successful check, the monitoring system shall also be considered out of control, beginning with the 169th unit or stack operating hour after the last successful check, and continuing until a subsequent system integrity check is passed. This weekly check is not required if the daily calibration assessments in section 2.1.1 of this appendix are performed using a NIST-traceable source of oxidized Hg.

FIGURE 1 TO APPENDIX B OF PART 75--QUALITY ASSURANCE TEST REQUIREMENTS

Test	QA test frequency requirements*				
	Daily*	Weekly	Quarterly*	Semiannual*	Annual
Calibration Error or System Integrity Check** (2 pt.)	✓				
Interference Check (flow)	✓				
Flow-to-Load Ratio			✓		
Leak Check (DP flow monitors)			✓		
Linearity Check or System Integrity Check** (3 pt.)			✓		
Single-point System Integrity Check**					
RATA (SO_2, NO_x, CO_2, O_2, H_2O)[1]				✓	
RATA (All Hg monitoring systems)				✓	
RATA (flow)[1,2]					

* "Daily" means operating days, only. "Weekly" means once every 168 unit or stack operating hours. "Quarterly" means once every QA operating quarter. "Semiannual" means once every two QA operating quarters. "Annual" means once every four QA operating quarters.

** The system integrity check applies only to Hg monitors with converters. The single-point weekly check is not required if daily system integrity checks are performed using a NIST-traceable source of oxidized Hg.

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

[2] For flow monitors installed on peaking units, bypass stacks, or units that qualify for single-level RATA testing under section 6.5.2 (e) of this part, conduct all RATAs at a single, normal load (or operating level). For other flow monitors, conduct annual RATAs at two load levels (or operating levels). Alternating single-load and 2-load (or single-level and 2-level) RATAs may be done if a monitor is on a semiannual frequency. A single-load (or single-level) RATA may be done in lieu of a 2-load (or 2-level) RATA if, since the last annual flow RATA, the unit has operated at one load level (or operating level) for ≥ 85.0 percent of the time. A 3-level RATA is required at least once every five calendar years and whenever a flow monitor is re-linearized, except for flow monitors exempted from 3-level RATA testing under section 6.5.2 (b) or 6.5.2 (e) of appendix A to this part.

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

RATA	Semiannual[W] (percent)	Annual[W]
SO_2 or NO_x[Y]	7.5% < RA ≤ 10.0% or ± 15.0 ppm[X]	RA ≤ 7.5% or ± 12.0 ppm[X]
SO_2-diluent	7.5% < RA ≤ 10.0% or ± 0.030 lb/mmBtu[X]	RA ≤ 7.5% or ± 0.025 lb/mmBtu[X]
NO_x-diluent	7.5% < RA ≤ 10.0% or ± 0.020 lb/mmBtu[X]	RA ≤ 7.5% or ±0. 015 lb/mmBtu[X]
Flow	7.5% < RA ≤ 10.0% or ± 1.5 fps[X]	RA ≤ 7.5%
CO_2 or O_2	7.5% < RA ≤ 10.0% or ± 1.0% CO_2/O_2[X]	RA ≤ 7.5% or ± 0.7% CO_2/O_2[X]
Hg[x]		RA < 20.0% or ± 1.0 μg/dscm[X]
Moisture	7.5% < RA ≤ 10.0% or ± 1.5% H_2O[X]	RA ≤ 7.5% or ± 1.0% H_2O[2X]

[W] The deadline for the next RATA is the end of the second (if semiannual) or fourth (if annual) successive QA operating quarter following the quarter in which the CEMS was last tested. Exclude calendar quarters with fewer than 168 unit operating hours (or, for common stacks and bypass stacks, exclude quarters with fewer than 168 stack operating hours) in determining the RATA deadline. For SO_2 monitors, QA operating quarters in which only very low sulfur fuel as defined in § 72.2, 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.

[X] The difference between monitor and reference method mean values applies to moisture monitors, CO_2, and O_2 monitors, low emitters of SO_2, NO_x, or Hg, or and low flow, only. The specifications for Hg monitors also apply to sorbent trap monitoring systems.

[Y] A NO_x concentration monitoring system used to determine NO_x mass emissions under § 75.71.

Appendix C to Part 75 -- Missing Data Estimation Procedures

App. C § 1

1. Parametric Monitoring Procedure for Missing SO_2 Concentration or NO_x Emission Rate Data

App. C § 1.1

1.1 Applicability

The owner or operator of any affected unit equipped with post-combustion SO_2 or NO_x emission controls and SO_2 pollutant concentration monitors and/or NO_x continuous emission monitoring systems at the inlet and outlet of the emission control system may apply to the Administrator for approval and certification of a parametric, empirical, or process simulation method or model for calculating substitute data for missing data periods. Such methods may be used to parametrically estimate the removal efficiency of the SO_2 of postcombustion NO_x emission controls which, with the monitored inlet concentration or emission rate data, may be used to estimate the average concentration of SO_2 emissions or average emission rate of NO_x discharged to the atmosphere. After approval by the Administrator, such method or model may be used for filling in missing SO_2 concentration or NO_x emission rate data when data from the outlet SO_2 pollutant concentration monitor or outlet NO_x continuous emission monitoring system have been reported with an annual monitor data availability of 90.0 percent or more.

Base the empirical and process simulation methods or models on the fundamental chemistry and engineering principles involved in the treatment of pollutant gas. On a case-by-case basis, the Administrator may pre-certify commercially available process simulation methods and models.

App. C § 1.2

1.2 Petition Requirements

Continuously monitor, determine, and record hourly averages of the estimated SO_2 or NO_x removal efficiency and of the parameters specified below, at a minimum. The affected facility shall supply additional parametric information where appropriate. Measure the SO_2 concentration or NO_x emission rate, removal efficiency of the add-on emission controls, and the parameters for at least 2160 unit operating hours. Provide information for all expected operating conditions and removal efficiencies. At least 4 evenly spaced data points are required for a valid hourly average, except during periods of calibration, maintenance, or quality assurance activities, during which 2

data points per hour are sufficient. The Administrator will review all applications on a case-by-case basis.

App. C § 1.2.1 1.2.1 Parameters for Wet Flue Gas Desulfurization System

1.2.1.1 Number of scrubber modules in operation.

1.2.1.2 Total slurry rate to each scrubber module (gal per min).

1.2.1.3 In-line absorber pH of each scrubber module.

1.2.1.4 Pressure differential across each scrubber module (inches of water column).

1.2.1.5 Unit load (MWe).

1.2.1.6 Inlet and outlet SO_2 concentration as determined by the monitor or missing data substitution procedures.

1.2.1.7 Percent solids in slurry for each scrubber module.

1.2.1.8 Any other parameters necessary to verify scrubber removal efficiency, if the Administrator determines the parameters above are not sufficient.

App. C § 1.2.2 1.2.2 Parameters for Dry Flue Gas Desulfurization System

1.2.2.1 Number of scrubber modules in operation.

1.2.2.2 Atomizer slurry flow rate to each scrubber module (gal per min).

1.2.2.3 Inlet and outlet temperature for each scrubber module (°F).

1.2.2.4 Pressure differential across each scrubber module (inches of water column).

1.2.2.5 Unit load (MWe).

1.2.2.6 Inlet and outlet SO_2 concentration as determined by the monitor or missing data substitution procedures.

1.2.2.7 Any other parameters necessary to verify scrubber removal efficiency, if the Administrator determines the parameters above are not sufficient.

App. C § 1.2.3 1.2.3 Parameters for Other Flue Gas Desulfurization Systems

If SO_2 control technologies other than wet or dry lime or limestone scrubbing are selected for flue gas desulfurization, a corresponding empirical correlation or process simulation parametric method using appropriate parameters may be developed by the owner or operator of the affected unit, and then reviewed and approved or modified by the Administrator on a case-by-case basis.

App. C § 1.2.4 1.2.4 Parameters for Post-Combustion NO_x Emission Controls

1.2.4.1 Inlet air flow rate to the unit (boiler) (mcf/hr).

1.2.4.2 Excess oxygen concentration of flue gas at stack outlet (percent).

1.2.4.3 Carbon monoxide concentration of flue gas at stack outlet (ppm).

1.2.4.4 Temperature of flue gas at outlet of the unit (°F).
1.2.4.5 Inlet and outlet NO_x emission rate as determined by the NO_x continuous emission

monitoring system or missing data substitution procedures.

1.2.4.6 Any other parameters specific to the emission reduction process necessary to verify the NO_x control removal efficiency, (e.g., reagent feedrate in gal/mi).

App. C § 1.3 *1.3 Correlation of Emissions With Parameters*

Establish a method for correlating hourly averages of the parameters identified above with the percent removal efficiency of the SO_2 or post-combustion NO_x emission controls under varying unit operating loads. Equations 1-7 in § 75.15 may be used to estimate the percent removal efficiency of the SO_2 emission controls on an hourly basis.

Each parametric data substitution procedure should develop a data correlation procedure to verify the performance of the SO_2 emission controls or post-combustion NO_x emission controls, along with the SO_2 pollutant concentration monitor and NO_x continuous emission monitoring system values for varying unit load ranges.

For NO_x emission rate data, and wherever the performance of the emission controls varies with the load, use the load range procedure provided in section 2.2 of this appendix.

App. C § 1.4 *1.4 Calculations*

App. C § 1.4.1 1.4.1 Use the following equation to calculate substitute data for filling in missing (outlet) SO_2 pollutant concentration monitor data.

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

(Eq. C-1)

Where,

M_o = Substitute data for outlet SO_2 concentration, ppm.

I_c = Recorded inlet SO_2 concentration, ppm.

E = Removal efficiency of SO_2 emission controls as determined by the correlation procedure described in section 1.3 of this appendix.

App. C § 1.4.2 1.4.2 Use the following equation to calculate substitute data for filling in missing (outlet) NO_x emission rate data.

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

(Eq. C-2)

Where,

M_o = Substitute data for outlet NO_x emission rate, lb/mmBtu.

I_c = Recorded inlet NO_x emission rate, lb/mmBtu.

E = Removal efficiency of post-combustion NO_x emission controls determined by the correlation procedure described in section 1.3 of this appendix.

App. C § 1.5 *1.5 Missing Data*

1.5.1 If both the inlet and the outlet SO_2 pollutant concentration monitors are unavailable simultaneously, use the maximum inlet SO_2 concentration recorded by the inlet SO_2 pollutant concentration monitor during the previous 720 quality assured monitor operating hours to substitute for the inlet SO_2 concentration in equation C-1 of this appendix.

1.5.2 If both the inlet and outlet NO_x continuous emission monitoring systems are unavailable simultaneously, use the maximum inlet NO_x emission rate for the corresponding unit load recorded by the NO_x continuous emission monitoring system at the inlet during the previous 2160 quality assured monitor operating hours to substitute for the inlet NO_x emission rate in equation C- 2 of this appendix.

App. C § 1.6 *1.6 Application*

Apply to the Administrator for approval and certification of the parametric substitution procedure for filling in missing SO_2 concentration or NO_x emission rate data using the established criteria and information identified above. Do not use this procedure until approved by the Administrator.

App. C § 2 2. Load-based Procedure for Missing Flow Rate, NO_x Concentration, and NO_x Emission Rate Data

App. C § 2.1 *2.1 Applicability*

This procedure is applicable for data from all affected units for use in accordance with the provisions of this part to provide substitute data for volumetric flow rate (scfh), NO_x emission rate (in lb/mmBtu) from NO_x-diluent continuous emission monitoring systems, and NO_x concentration data (in ppm) from NO_x concentration monitoring systems used to determine NO_x mass emissions.

App. C § 2.2 *2.2 Procedure*

App. C § 2.2.1 2.2.1 For a single unit, establish ten operating load ranges defined in terms of percent of the maximum hourly average gross load of the unit, in gross megawatts (MWge), as shown in Table C- 1. (Do not use integrated hourly gross load in MW-hr.) For units sharing a common stack monitored with a single flow monitor, the load ranges for flow (but not for NO_x) may be broken down into 20 operating load ranges in increments of 5.0 percent of the combined maximum hourly average gross load of all units utilizing the common stack. If this option is selected, the twentieth (uppermost) operating load range shall include all values greater than 95.0 percent of the maximum hourly average gross load. For a cogenerating unit or other unit at which some portion of the heat input is not used to produce electricity or for a unit for which hourly average gross load in MWge is not recorded separately, use the hourly gross steam load of the unit, in pounds of steam per hour at the measured temperature (°F) and pressure (psia) instead of MWge. Indicate a change in the number of load ranges or the units of loads to be used in the precertification section of the monitoring plan.

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

Operating load range	Percent of maximum hourly gross load or maximum hourly gross steam load (percent)
1	0-10
2	>10-20
3	>20-30
4	>30-40
5	>40-50
6	>50-60
7	>60-70
8	>70-80
9	>80-90
10	>90

App. C § 2.2.2 2.2.2 Beginning with the first hour of unit operation after installation and certification of the flow

monitor or the NO_x-diluent continuous emission monitoring system (or a NO_x concentration monitoring system used to determine NO_x mass emissions, as defined in § 75.71(a)(2)), for each hour of unit operation record a number, 1 through 10, (or 1 through 20 for flow at common stacks) that identifies the operating load range corresponding to the integrated hourly gross load of the unit(s) recorded for each unit operating hour.

App. C § 2.2.3

2.2.3 Beginning with the first hour of unit operation after installation and certification of the flow monitor or the NO_x-diluent continuous emission monitoring system (or a NO_x concentration monitoring system used to determine NO_x mass emissions, as defined in § 75.71(a)(2)) and continuing thereafter, the data acquisition and handling system must be capable of calculating and recording the following information for each unit operating hour of missing flow or NO_x data within each identified load range during the shorter of: (a) the previous 2,160 quality assured monitor operating hours (on a rolling basis), or (b) all previous quality assured monitor operating hours.

2.2.3.1 Average of the hourly flow rates reported by a flow monitor, in scfh.

2.2.3.2 The 90th percentile value of hourly flow rates, in scfh.

2.2.3.3 The 95th percentile value of hourly flow rates, in scfh.

2.2.3.4 The maximum value of hourly flow rates, in scfh.

2.2.3.5 Average of the hourly NO_x emission rate, in lb/mmBtu, reported by a NO_x continuous emission monitoring system.

2.2.3.6 The 90th percentile value of hourly NO_x emission rates, in lb/mmBtu.

2.2.3.7 The 95th percentile value of hourly NO_x emission rates, in lb/mmBtu.

2.2.3.8 The maximum value of hourly NO_x emission rates, in lb/mmBtu.

2.2.3.9 Average of the hourly NO_x pollutant concentrations, in ppm, reported by a NO_x concentration monitoring system used to determine NO_x mass emissions, as defined in § 75.71(a)(2).

2.2.3.10 The 90th percentile value of hourly NO_x pollutant concentration, in ppm.

2.2.3.11 The 95th percentile value of hourly NO_x pollutant concentration, in ppm.

2.2.3.12 The maximum value of hourly NO_x pollutant concentration, in ppm.

App. C § 2.2.4

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

.App. C § 2.2.5

2.2.5 When a bias adjustment is necessary for the flow monitor and/or the NO_x-diluent continuous emission monitoring system (and/or the NO_x concentration monitoring system used to determine NO_x mass emissions, as defined in § 75.71(a)(2)), apply the adjustment factor to all monitor or continuous emission monitoring system data values placed in the load ranges.

App. C § 2.2.6

2.2.6 Use the calculated monitor or monitoring system data averages, maximum values, and percentile values to substitute for missing flow rate and NO_x emission rate data (and where applicable, NO_x concentration data) according to the procedures in subpart D of this part.

App. C § 3

3. Non-load-based Procedure for Missing Flow Rate, NO_x Concentration, and NO_x Emission Rate Data (Optional)

App. C § 3.1

3.1 *Applicability.*

For affected units that do not produce electrical output in megawatts or thermal output in klb/hr of steam, this procedure may be used in accordance with the provisions of this part to provide substitute data for volumetric flow rate (scfh), NO_x emission rate (in lb/mmBtu) from NO_x-diluent continuous emission monitoring systems, and NO_x concentration data (in ppm) from NO_x concentration monitoring systems used to determine NO_x mass emissions.

App. C § 3.2

3.2 *Procedure*

App. C § 3.2.1

3.2.1 For each monitored parameter (flow rate, NO_x emission rate, or NO_x concentration), establish at least two, but no more than ten operational bins, corresponding to various operating conditions and parameters (or combinations of these) that affect volumetric flow rate or NO_x emissions. Include a complete description of each operational bin in the hardcopy portion of the monitoring plan required under § 75.53(e)(2), identifying the unique combination of parameters and operating conditions associated with the bin and explaining the relationship between these parameters and conditions and the magnitude of the stack gas flow rate or NO_x emissions. Assign a unique number, 1 through 10, to each operational bin. Examples of conditions and parameters that may be used to define operational bins include unit heat input, type of fuel combusted, specific stages of an industrial process, or (for common stacks), the particular combination of units that are in operation.

App. C § 3.2.2

3.2.2 In the electronic quarterly report required under § 75.64, indicate for each hour of unit operation the operational bin associated with the NO_x or flow rate data, by recording the number assigned to the bin under section 3.2.1 of this appendix.

App. C § 3.2.3

3.2.3 The data acquisition and handling system must be capable of properly identifying and recording the operational bin number for each unit operating hour. The DAHS must also be capable of calculating and recording the following information (as applicable) for each unit operating hour of missing flow or NO_x data within each identified operational bin during the shorter of: (a) the previous 2,160 quality assured monitor operating hours (on a rolling basis), or (b) all previous quality assured monitor operating hours in the previous 3 years:

3.2.3.1 Average of the hourly flow rates reported by a flow monitor (scfh).

3.2.3.2 The 90th percentile value of hourly flow rates (scfh).

3.2.3.3 The 95th percentile value of hourly flow rates (scfh).

3.2.3.4 The maximum value of hourly flow rates (scfh).

3.2.3.5 Average of the hourly NO_x emission rates, in lb/mmBtu, reported by a NO_x-diluent continuous emission monitoring system.

3.2.3.6 The 90th percentile value of hourly NO_x emission rates (lb/mmBtu).

3.2.3.7 The 95th percentile value of hourly NO_x emission rates (lb/mmBtu).

3.2.3.8 The maximum value of hourly NO_x emission rates, in (lb/mmBtu).

3.2.3.9 Average of the hourly NO_x pollutant concentrations (ppm), reported by a NO_x concentration monitoring system used to determine NO_x mass emissions, as defined in § 75.51(c)(2).

3.2.3.10 The 90th percentile value of hourly NO_x pollutant concentration (ppm).

3.2.3.11 The 95th percentile value of hourly NO_x pollutant concentration (ppm).

3.2.3.12 The maximum value of hourly NO_x pollutant concentration (ppm).

App. C § 3.2.4 3.2.4 When a bias adjustment is necessary for the flow monitor and/or the NO_x-diluent continuous emission monitoring system (and/or the NO_x concentration monitoring system), apply the bias adjustment factor to all data values placed in the operational bins.

App. C § 3.2.5 3.2.5 Calculate all CEMS data averages, maximum values, and percentile values determined by this procedure using bias-adjusted values.

App. C § 3.2.6 3.2.6 Use the calculated monitor or monitoring system data averages, maximum values, and percentile values to substitute for missing flow rate and NO_x emission rate data (and where applicable, NO_x concentration data) according to the procedures in subpart D of this part.

Appendix D to Part 75 -- Optional SO_2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units

App. D § 1 **1. Applicability**

App. D § 1.1 *1.1* This protocol may be used in lieu of continuous SO_2 pollutant concentration and flow monitors for the purpose of determining hourly SO_2 mass emissions and heat input from: gas-fired units, as defined in § 72.2 of this chapter, or oil-fired units, as defined in § 72.2 of this chapter. Section 2.1 of this appendix provides procedures for measuring oil or gaseous fuel flow using a fuel flowmeter, section 2.2 of this appendix provides procedures for conducting oil sampling and analysis to determine sulfur content and gross calorific value (GCV) of fuel oil, and section 2.3 of this appendix provides procedures for determining the sulfur content and GCV of gaseous fuels.

App. D § 1.2 *1.2* Pursuant to the procedures in § 75.20, complete all testing requirements to certify use of this protocol in lieu of a flow monitor and an SO_2 continuous emission monitoring system. Complete all testing requirements no later than the applicable deadline specified in § 75.4. Apply to the Administrator for initial certification to use this protocol no later than 45 days after the completion of all certification tests.

App. D § 2 **2. Procedure**

App. D § 2.1 *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.

App. D § 2.1.1 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).

App. D § 2.1.2

2.1.2 Install and use fuel flowmeters meeting the requirements of this appendix in a pipe going to each unit, or install and use a fuel flowmeter in a common pipe header (as defined in § 72.2). However, the use of a fuel flowmeter in a common pipe header and the provisions of sections 2.1.2.1 and 2.1.2.2 of this appendix shall not apply to any unit that is using the provisions of subpart H of this part to monitor, record, and report NO_x mass emissions under a State or federal NO_x mass emission reduction program, unless both of the following are true: all of the units served by the common pipe are affected units, and all of the units have similar efficiencies. When a fuel flowmeter is installed in a common pipe header, proceed as follows:
2.1.2.1 Measure the fuel flow rate in the common pipe, and combine SO_2 mass emissions (Acid Rain Program units only) for the affected units for recordkeeping and compliance purposes; and

2.1.2.2 Apportion the heat input rate measured at the common pipe to the individual units, using Equation F-21a, F-21b, or F-21d in appendix F to this part.

App. D § 2.1.3

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.

App. D § 2.1.4

2.1.4 Situations in Which Certified Flowmeter Is Not Required

App. D § 2.1.4.1

2.1.4.1 Start-up or Ignition Fuel

For an oil-fired unit that uses gas solely for start-up or burner ignition, a gas-fired unit that uses oil solely for start-up or burner ignition, or an oil-fired unit that uses a different grade of oil solely for start-up or burner ignition, a fuel flowmeter for the start-up fuel is permitted but not required. Estimate the volume of oil combusted for each start-up or ignition either by using a fuel flowmeter or by using the dimensions of the storage container and measuring the depth of the fuel in the storage container before and after each start-up or ignition. A fuel flowmeter used solely for start-up or ignition fuel is not subject to the calibration requirements of sections 2.1.5 and 2.1.6 of this appendix. Gas combusted solely for start-up or burner ignition does not need to be measured separately.

App. D § 2.1.4.2

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.

App. D § 2.1.4.3

2.1.4.3 Emergency Fuel

The designated representative of a unit that is restricted by its Federal, State or local permit to combusting a particular fuel only during emergencies where the primary fuel is not available is exempt from certifying a fuel flowmeter for use during combustion of the emergency fuel. During any hour in which the emergency fuel is combusted, report the hourly heat input to be the maximum rated heat input of the unit for the fuel. Use the maximum potential sulfur content for the fuel (from Table D-6 of this appendix) and the fuel flow rate corresponding to the maximum hourly heat input to calculate the hourly SO_2 mass emission rate, using Equations D-2 through D-4 (as applicable). Alternatively, if a certified fuel flowmeter is available for the emergency fuel, you may use the measured hourly fuel flow rates in the calculations. Also, if daily samples or weekly composite samples (fuel oil, only) of the fuel's total sulfur content, GCV, and (if applicable) density are taken during the combustion of the emergency fuel, as described in section 2.2 or 2.3 of this appendix, the sample results may be used to calculate the hourly SO_2 emissions and heat input rates, in lieu of using maximum potential values. The designated representative shall also provide notice under § 75.61(a)(6) for each period when the emergency fuel is combusted.

App. D § 2.1.5

2.1.5 Initial Certification Requirement for all Fuel Flowmeters

For the purposes of initial certification, each fuel flowmeter used to meet the requirements of this protocol shall meet a flowmeter accuracy of 2.0 percent of the upper range value (i.e. maximum fuel flow rate measurable by the flowmeter) across the range of fuel flow rate to be measured at the unit. Flowmeter accuracy may be determined under section 2.1.5.1 of this appendix for initial certification in any of the following ways (as applicable): by design (orifice, nozzle, and venturi-type flowmeters, only) or by measurement under laboratory conditions; by the manufacturer; by an independent laboratory; or by the owner or operator. Flowmeter accuracy may also be determined under section 2.1.5.2 of this appendix by in-line comparison against a reference flowmeter.

App. D § 2.1.5.1

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 (Reaffirmed 1995) ~~with September 1990 Errata~~ ("Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi"); ASME MFC-4M-1986 (Reaffirmed ~~1990~~ 1997), "Measurement of Gas Flow by Turbine Meters;" American Gas Association Report No. 3, "Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids Part 1: General Equations and Uncertainty Guidelines" (October 1990 Edition), Part 2: "Specification and Installation Requirements" (February 1991 Edition), and Part 3: "Natural Gas Applications" (August 1992 edition) (excluding the modified flow-calculation method in part 3); Section 8, Calibration from American Gas Association Transmission Measurement Committee Report No. 7: Measurement of Gas by Turbine Meters (Second Revision, April 1996); ASME MFC-5M-1985 (Reaffirmed 2001) ("Measurement of Liquid Flow in Closed Conduits Using Transit- Time Ultrasonic Flowmeters"); ASME MFC-6M-1998~~1987 with June 1987 Errata~~ ("Measurement of Fluid Flow in Pipes Using Vortex Flow Meters"); ASME MFC-7M-1987 (Reaffirmed ~~1992~~ 2001), "Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles;" ISO 8316: 1987(E) "Measurement of Liquid Flow in Closed Conduits--Method by Collection of the Liquid in a Volumetric Tank;" American Petroleum Institute (API) Manual of Measurement Standards, Chapter 4: Section 2, "Conventional Pipe Provers" (Provers Accumulating at Least 10,000 Pulses), Measurement Coordination (Second Edition, March 2001), Section 3, "Small Volume Provers" (First Edition), and Section 5, "Master-Meter Provers", Measurement Coordination (Second Edition, May 2000) ~~from Chapter 4 of the Manual of Petroleum Measurement Standards, October 1988 (Reaffirmed 1993)~~; API Manual of Petroleum Measurement Standards, Chapter 22: Section 2, "Differential Pressure Flow Measurement Devices" (First Edition, August 2005); or ASME MFC-9M-1988 (Reaffirmed 2001) ~~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.

App. D § 2.1.5.2(a)

2.1.5.2 (a) Alternatively, determine the flowmeter accuracy of a fuel flowmeter used for the purposes of this part by comparing it to the measured flow from a reference flowmeter which has been either designed according to the specifications of American Gas Association Report No. 3 or ASME MFC-3M-1989, as cited in section 2.1.5.1 of this appendix, or tested for accuracy during the previous 365 days, using a standard listed in section 2.1.5.1 of this appendix or other procedure approved by the Administrator under § 75.66 (all standards incorporated by reference under § 75.6). Any secondary elements, such as pressure and temperature transmitters, must be calibrated immediately prior to the comparison. Perform the comparison over a period of no more than seven consecutive unit operating days. Compare the average of three fuel flow rate readings over 20 minutes or longer for each meter at each of three different flow rate levels. The three flow rate levels shall correspond to:

(1) Normal full unit operating load,

(2) Normal minimum unit operating load,

(3) A load point approximately equally spaced between the full and minimum unit operating loads, and

App. D § 2.1.5.2(b)

(b) Calculate the flowmeter accuracy at each of the three flow levels using the following equation:

$$ACC = \frac{|R - A|}{URV} x\,100$$

(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).

App. D § 2.1.5.2(c)

(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).

App. D § 2.1.5.3

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.

App. D § 2.1.5.4

2.1.5.4 For purposes of initial certification, when a flowmeter is tested against a reference fuel flow rate (i.e., fuel flow rate from another fuel flowmeter under section 2.1.5.2 of this appendix or flow rate from a procedure performed according to a standard incorporated by reference under section 2.1.5.1 of this appendix), report the results of flowmeter accuracy tests in a manner consistent with Table D-1.

TABLE D-1. -- TABLE OF FLOWMETER ACCURACY RESULTS					
Test number:____ Test completion date[1]:_____ Test completion time[1]:_____ Reinstallation date[2] (for testing under 2.1.5.1 only):_____ Reinstallation time [2]:_____ Unit or pipe ID: _____ Component/System ID: _____ Flowmeter serial number: _____ Upper range value: _____ Units of measure for flowmeter and reference flow readings: _____					
Measurement level (percent of URV)	**Run No.**	**Time of run (HHMM)**	**Candidate flowmeter reading**	**Reference flow reading**	**Percent accuracy (percent of URV)**
Low (Minimum) level __ percent[3] of URV	1				
	2				
	3				
	Average				
Mid-level __ percent[3] of URV	1				
	2				
	3				
	Average				
High (Maximum) level __ percent[3] of URV	1				
	2				
	3				
	Average				

[1] Report the date, hour, and minute that all test runs were completed.
[2] For laboratory tests not performed inline, report the date and hour that the fuel flowmeter was reinstalled following the test.
[3] It is required to test at least at three different levels: (1) normal full unit operating load, (2) normal minimum unit operating load, and (3) a load point approximately equally spaced between the full and minimum unit operating loads.

App. D § 2.1.6

2.1.6 Quality Assurance

App. D § 2.1.6(a)

(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.

App. D § 2.1.6(b)

(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

App. D § 2.1.6(c) flowmeter accuracy testing using the procedures in section 2.1.5.2 of this appendix or perform a transmitter accuracy test for the initial certification and once every four fuel flowmeter QA operating quarters thereafter. Perform a primary element visual inspection for the initial certification and once every 12 calendar quarters thereafter, according to the procedures in sections 2.1.6.1 through 2.1.6.4 of this appendix for periodic quality assurance.

App. D § 2.1.6(d) (d) Notwithstanding the requirements of this section, if the procedures of section 2.1.7 (fuel flow-to-load test) of this appendix are performed during each fuel flowmeter QA operating quarter, subsequent to a required flowmeter accuracy test or (if applicable) transmitter accuracy test and primary element inspection, those procedures may be used to meet the requirement for periodic quality assurance testing for a period of up to 20 calendar quarters from the previous accuracy test or (if applicable) transmitter accuracy test and primary element inspection.

App. D § 2.1.6(e) (e) When accuracy testing of the orifice, nozzle, or venturi meter is performed according to section 2.1.5.2 of this appendix, record the information displayed in Table D-1 in this section. At a minimum, record the overall accuracy results for the fuel flowmeter at the three flow rate levels specified in section 2.1.5.2 of this appendix.

App. D § 2.1.6(f) (f) Report the results of all fuel flowmeter accuracy tests, transmitter or transducer accuracy tests, and primary element inspections, as applicable, in the emissions report for the quarter in which the quality assurance tests are performed, using the electronic format specified by the Administrator under § 75.64.

App. D § 2.1.6.1 2.1.6.1 Transmitter or Transducer Accuracy Test for Orifice-, Nozzle-, and Venturi-Type Flowmeters

App. D § 2.1.6.1(a) (a) Calibrate the differential pressure transmitter or transducer, static pressure transmitter or transducer, and temperature transmitter or transducer, as applicable, using equipment that has a current certificate of traceability to NIST standards. Check the calibration of each transmitter or transducer by comparing its readings to that of the NIST traceable equipment at least once at each of the following levels: the zero-level and at least two other upscale levels (e.g., "mid" and "high"), such that the full range of transmitter or transducer readings corresponding to normal unit operation is represented. For temperature transmitters, the zero and upscale levels may correspond to fixed reference points, such as the freezing point or boiling point of water.

App. D § 2.1.6.1(b) (b) Calculate the accuracy of each transmitter or transducer at each level tested, using the following equation:

$$ACC = \frac{|R - T|}{FS} x\, 100$$

(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).

App. D § 2.1.6.1(c) (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.

App. D § 2.1.6.2

2.1.6.2 Recordkeeping for Transmitter or Transducer Accuracy Results

App. D § 2.1.6.2(a)

(a) Record the accuracy of the orifice, nozzle, or venturi meter or its individual transmitters or transducers and keep this information in a file at the site or other location suitable for inspection.

TABLE D-2. -- TABLE OF FLOWMETER TRANSMITTER OR TRANSDUCER ACCURACY RESULTS

Test number:____ Test completion date:_____ Unit or pipe ID:_____

Flowmeter serial number: _____ Component/System ID: _____

Full-scale value: _____ Units of measure[3]: _____

Transducer/Transmitter Type (check one): ___ Differential Pressure
___ Static Pressure
___ Temperature

Measurement level (percent of full-scale)	**Run no. (if multiple runs)[2]**	**Run time (HHMM)**	**Transmitter/ transducer input (pre-calibration)**	**Expected transmitter/ transducer output (reference)**	**Actual transmitter/ transducer output[3]**	**Percent accuracy (percent of full-scale)**
Low (Minimum) level __ percent[1] of full-scale						
Mid-level __ percent[1] of full-scale						
(If tested at more than 3 levels) 2nd Mid-level __ percent[1] of full-scale						
(If tested at more than 3 levels) 3rd Mid-level __ percent[1] of full-scale						
High (Maximum) level __ percent[1] of full-scale						

[1] At a minimum, it is required to test at zero-level and at least two other levels across the range of the transmitter or transducer readings corresponding to normal unit operation.
[2] It is required to test at least once at each level.
[3] Use the same units of measure for all readings (e.g., use degrees (°), inches of water (in H_2O), pounds per square inch (psi), or milliamperes (ma) for both transmitter or transducer readings and reference readings).

App. D § 2.1.6.2(b) (b) [Reserved]

App. D § 2.1.6.2(c) (c) [Reserved]

App. D § 2.1.6.3 2.1.6.3 Failure of Transducer(s) or Transmitter(s)

If, during a transmitter or transducer accuracy test conducted according to section 2.1.6.1 of this appendix, the flowmeter accuracy specification of 2.0 percent is not met at any of the levels tested, repair or replace transmitter(s) or transducer(s) as necessary until the flowmeter accuracy specification has been achieved at all levels. (Note that only transmitters or transducers which are repaired or replaced need to be re-tested; however, the re-testing is required at all three measurement levels, to ensure that the flowmeter accuracy specification is met at each level). The fuel flowmeter is "out-of-control" and data from the flowmeter are considered invalid, beginning with the date and hour of the failed accuracy test and continuing until the date and hour of completion of a successful transmitter or transducer accuracy test at all levels. In addition, if, during normal operation of the fuel flowmeter, one or more transmitters or transducers malfunction, data from the fuel flowmeter shall be considered invalid from the hour of the transmitter or transducer failure until the hour of completion of a successful 3-level transmitter or transducer accuracy test. During fuel flowmeter out-of-control periods, provide data from another fuel flowmeter that meets the requirements of § 75.20(d) and section 2.1.5 of this appendix, or substitute for fuel flow rate using the missing data procedures in section 2.4.2 of this appendix. Record and report test data and results, consistent with sections 2.1.6.1 and 2.1.6.2 of this appendix and § 75.59.

App. D § 2.1.6.4 2.1.6.4 Primary Element Inspection

App. D § 2.1.6.4(a) (a) Conduct a visual inspection of the orifice, nozzle, or venturi meter at least once every twelve calendar quarters. Notwithstanding this requirement, the procedures of section 2.1.7 of this appendix may be used to reduce the inspection frequency of the orifice, nozzle, or venturi meter to at least once every twenty calendar quarters. The inspection may be performed using a baroscope. If the visual inspection is failed (if the orifice, nozzle, or venturi meter has become damaged or corroded), then:

(1) Replace the primary element with another primary element meeting the requirements of American Gas Association Report No. 3 or ASME MFC-3M-1989, as cited in section 2.1.5.1 of this appendix (both standards incorporated by reference under § 75.6); If the primary element size is changed, also calibrate the transmitters or transducers, consistent with the new primary element size;

(2) Replace the primary element with another primary element, and demonstrate that the overall flowmeter accuracy meets the accuracy specification in section 2.1.5 of this appendix, using the procedures of section 2.1.5.2 of this appendix; or

(3) Restore the damaged or corroded primary element to "as new" condition; determine the overall accuracy of the flowmeter, using either the specifications of American Gas Association Report No. 3 or ASME MFC-3M-1989, as cited in section 2.1.5.1 of this appendix (both standards incorporated by reference under § 75.6); and retest the transmitters or transducers prior to providing quality assured data from the flowmeter.

App. D § 2.1.6.4(b) (b) Data from the fuel flowmeter are considered invalid, beginning with the date and hour of a failed visual inspection and continuing until the date and hour when:

(1) The damaged or corroded primary element is replaced with another primary element meeting the requirements of American Gas Association Report No. 3 or ASME MFC-3M-1989, as cited in section 2.1.5.1 of this appendix (both standards incorporated by reference under § 75.6) and, if applicable, the transmitters have been successfully recalibrated;

(2) The damaged or corroded primary element is replaced, and the overall accuracy of the flowmeter is demonstrated to meet the accuracy specification in section 2.1.5 of this appendix, using the procedures of section 2.1.5.2 of this appendix; or

(3) The restored primary element is installed to meet the requirements of American Gas Association Report No. 3 or ASME MFC-3M-1989, as cited in section 2.1.5.1 of this appendix (both standards incorporated by reference under § 75.6) and its transmitters or transducers are

retested to meet the accuracy specification in section 2.1.6.1 of this appendix.

App. D § 2.1.6.4(c) (c) During each period of invalid fuel flowmeter data described in paragraph (b) of this section, provide data from another fuel flowmeter that meets the requirements of § 75.20(d) and section 2.1.5 of this appendix, or substitute for fuel flow rate using the missing data procedures in section 2.4.2 of this appendix.

App. D § 2.1.7 2.1.7 Fuel Flow-to-Load Quality Assurance Testing for Certified Fuel Flowmeters

The procedures of this section may be used as an optional supplement to the quality assurance procedures in section 2.1.5.1, 2.1.5.2, 2.1.6.1, or 2.1.6.4 of this appendix when conducting periodic quality assurance testing of a certified fuel flowmeter. Note, however, that these procedures may not be used unless the 168-hour baseline data requirement of section 2.1.7.1 of this appendix has been met. If, following a flowmeter accuracy test or (if applicable) a flowmeter transmitter test and primary element inspection, the procedures of this section are performed during each subsequent fuel flowmeter QA operating quarter, as defined in § 72.2 of this chapter (excluding the quarter(s) in which the baseline data are collected), then these procedures may be used to meet the requirement for periodic quality assurance for a period of up to 20 calendar quarters from the previous periodic quality assurance procedure(s) performed according to sections 2.1.5.1, 2.1.5.2, or 2.1.6.1 through 2.1.6.4 of this appendix. The procedures of this section are not required for any quarter in which a flowmeter accuracy test or (if applicable) a transmitter accuracy test and a primary element inspection, are conducted. Notwithstanding the requirements of § 75.57(a), when using the procedures of this section, keep records of the test data and results from the previous flowmeter accuracy test under section 2.1.5.1 or 2.1.5.2 of this appendix, records of the test data and results from the previous transmitter or transducer accuracy test under section 2.1.6.1 of this appendix for orifice-, nozzle-, and venturi-type fuel flowmeters, and records of the previous visual inspection of the primary element required under section 2.1.6.4 of this appendix for orifice-, nozzle-, and venturi-type fuel flowmeters until the next flowmeter accuracy test, transmitter accuracy test, or visual inspection is performed, even if the previous flowmeter accuracy test, transmitter accuracy test, or visual inspection was performed more than three years previously.

App. D § 2.1.7.1 2.1.7.1 Baseline Flow Rate-to-Load Ratio or Heat Input-to-Load Ratio

App. D § 2.1.7.1(a) (a) Determine R_{base}, the baseline value of the ratio of fuel flow rate to unit load, following each successful periodic quality assurance procedure performed according to sections 2.1.5.1, 2.1.5.2, or 2.1.6.1 and 2.1.6.4 of this appendix. Establish a baseline period of data consisting, at a minimum, of 168 hours of quality assured fuel flowmeter data. Baseline data collection shall begin with the first hour of fuel flowmeter operation following completion of the most recent quality assurance procedure(s), during which only the fuel measured by the fuel flowmeter is combusted (e.g., only gas, only residual oil, or only diesel fuel is combusted by the unit). During the baseline data collection period, the owner or operator may exclude as non-representative any hour in which the unit is "ramping" up or down, (i.e., the load during the hour differs by more than 15.0 percent from the load in the previous or subsequent hour) and may exclude any hour in which the unit load is in the lower 25.0 percent of the range of operation, as defined in section 6.5.2.1 of appendix A to this part (unless operation in this lower 25.0 percent of the range is considered normal for the unit). The baseline data must be obtained no later than the end of the fourth calendar quarter following the calendar quarter of the most recent quality assurance procedure for that fuel flowmeter. For orifice-, nozzle-, and venturi-type fuel flowmeters, if the fuel flow-to-load ratio is to be used as a supplement both to the transmitter accuracy test under section 2.1.6.1 of this appendix and to primary element inspections under section 2.1.6.4 of this appendix, then the baseline data must be obtained after both procedures are completed and no later than the end of the fourth calendar quarter following the calendar quarter in which both procedures were completed. From these 168 (or more) hours of baseline data, calculate the baseline fuel flow rate-to-load ratio as follows:

$$R_{base} = \frac{Q_{base}}{L_{avg}}$$

(Eq. D-1b)
Where:

R_{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, or 100 scfh/mmBtu per hour thermal output for gas-firing; (lb/hr)/MWe, ~~or~~ (lb/hr)/klb per hour steam load, or (lb/hr)/mmBtu per hour thermal output for oil-firing.

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

L_{avg} = Arithmetic average unit load during the baseline period, megawatts, ~~or~~ 1000 lb/hr of steam, or mmBtu/hr thermal output.

App. D § 2.1.7.1(b) (b) In Equation D-1b, for a fuel flowmeter installed on a common pipe header, L_{avg} is the sum of the operating loads of all units that received fuel through the common pipe header during the baseline period, divided by the total number of hours of fuel flow rate data collected during the baseline period. For a unit that receives the same type of fuel through multiple pipes, Q_{base} is the sum of the fuel flow rates during the baseline period from all of the pipes, divided by the total number of hours of fuel flow rate data collected during the baseline period. Round off the value of R_{base} to the nearest tenth.

App. D § 2.1.7.1(c) (c) Alternatively, a baseline value of the gross heat rate (GHR) may be determined in lieu of R_{base}. The baseline value of the GHR, GHR_{base}, shall be determined as follows:

$$(GHR)_{base} = \frac{(Heat\ Input)_{avg}}{L_{avg}}\ x\ 1000$$

(Eq. D-1c)
Where:

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

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

L_{avg} = Average (mean) unit load during the baseline period, megawatts, ~~or~~ 1000 lb/hr of steam, or mmBtu/hr thermal output.

App. D § 2.1.7.1(d) (d) Report the current value of R_{base} (or GHR_{base}) and the completion date of the associated quality assurance procedure in each electronic quarterly report required under § 75.64.

(e) If a unit co-fires different fuels (e.g., oil and natural gas) as its normal mode of operation, the gross heat rate option in paragraph (c) of this section may be used to determine a value of $(GHR)_{base}$, as follows. Derive the baseline data during co-fired hours. Then, use Equation D-1c to calculate $(GHR)_{base}$, making sure that each hourly unit heat input rate used to calculate $(Heat\ Input)_{avg}$ includes the contribution of each type of fuel.

App. D § 2.1.7.2 2.1.7.2 Data Preparation and Analysis

App. D § 2.1.7.2(a) (a) Evaluate the fuel flow rate-to-load ratio (or GHR) for each fuel flowmeter QA operating quarter, as defined in § 72.2 of this chapter. At the end of each fuel flowmeter QA operating quarter, use Equation D-1d in this appendix to calculate R_h, the hourly fuel flow-to-load ratio, for every quality assured hourly average fuel flow rate obtained with a certified fuel flowmeter. Alternatively, the owner or operator may exclude non-representative hours from the data analysis, as described in section 2.1.7.3 of this appendix, prior to calculating the values of R_h.

$$R_h = \frac{Q_h}{L_h}$$

(Eq. D-1d)

Where:

R_h = Hourly value of the fuel flow rate-to-load ratio; 100 scfh/MWe, (lb/hr)/MWe, 100 scfh/1000 lb/hr of steam load, ~~or~~ (lb/hr)/1000 lb/hr of steam load, 100 scfh/(mmBtu/hr of steam load), or (lb/hr)/(mmBtu/hr thermal output).

Q_h = Hourly fuel flow rate, as measured by the fuel flowmeter, 100 scfh for gas-firing or lb/hr for oil-firing.

L_h = Hourly unit load, megawatts, ~~or~~ 1000 lb/hr of steam, or mmBtu/hr thermal output.

App. D § 2.1.7.2(b) (b) For a fuel flowmeter installed on a common pipe header, L_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 the same type of fuel through multiple pipes, Q_h will be the sum of the fuel flow rates from all of the pipes. Round off each value of R_h to the nearest tenth.

App. D § 2.1.7.2(c) (c) Alternatively, calculate the hourly gross heat rates (GHR) in lieu of the hourly flow-to-load ratios. If this option is selected, calculate each hourly GHR value as follows:

$$(GHR)_h = \frac{(Heat\ Input)_h}{L_h} \times 1000$$

(Eq. D-1e)

Where:

$(GHR)_h$ = Hourly value of the gross heat rate, Btu/kwh, ~~or~~ Btu/lb steam load, or mmBtu heat input/mmBtu thermal output.

$(Heat\ Input)_h$ = Hourly heat input rate, as determined using the hourly fuel flow rate and the fuel GCV in the applicable equation in appendix F to this part, mmBtu/hr.

L_h = Hourly unit load, megawatts, ~~or~~ 1000 lb/hr of steam, or mmBtu/hr thermal output.

App. D § 2.1.7.2(d) (d) Evaluate the calculated flow rate-to-load ratios (or gross heat rates) as follows.

(1) Perform a separate data analysis for each fuel flowmeter system following the procedures of this section. Base each analysis on a minimum of 168 hours of data. If, for a particular fuel flowmeter system, fewer than 168 hourly flow-to-load ratios (or GHR values) are available, or, if the baseline data collection period is still in progress at the end of the quarter and fewer than four calendar quarters have elapsed since the quarter in which the last successful fuel flowmeter system accuracy test was performed, a flow-to-load (or GHR) evaluation is not required for that flowmeter system for that calendar quarter. A one-quarter extension of the deadline for the next fuel flowmeter system accuracy test may be claimed for a quarter in which there is insufficient hourly data available to analyze or a quarter that ends with the baseline data collection period still in progress.

(2) For a unit that normally co-fires different types of fuel (e.g., oil and natural gas), include the contribution of each type of fuel in the value of $(Heat\ Input)_h$, when using Equation D-1e.

App. D § 2.1.7.2(e) (e) For each hourly flow-to-load ratio or GHR value, calculate the percentage difference (percent D_h) from the baseline fuel flow-to-load ratio using Equation D-1f.

$$\%\,D_h = \frac{|R_{base} - R_h|}{R_{base}} \times 100$$

(Eq. D-1f)

Where:

$\%D_h$ = Absolute value of the percentage difference between the hourly fuel flow rate-to-load ratio and the baseline value of the fuel flow rate-to-load ratio (or hourly and baseline GHR).

R_h = The hourly fuel flow rate-to-load ratio (or GHR).

R_{base} = The value of the fuel flow rate-to-load ratio (or GHR) from the baseline period, determined in accordance with section 2.1.7.1 of this appendix.

App. D § 2.1.7.2(f) (f) Consistently use R_{base} and R_h in Equation D-1f if the fuel flow-to-load ratio is being evaluated, and consistently use $(GHR)_{base}$ and $(GHR)_h$ in Equation D-1f if the gross heat rate is being evaluated.

App. D § 2.1.7.2(g) (g) Next, determine the arithmetic average of all of the hourly percent difference (percent D_h) values using Equation D-1g, as follows:

$$E_f = \sum_{h=1}^{q} \frac{\% D_h}{q}$$

(Eq. D-1g)
Where,
E_f = Quarterly average percentage difference between hourly flow rate-to-load ratios and the baseline value of the fuel flow rate-to-load ratio (or hourly and baseline GHR).
$\%D_h$ = Percentage difference between the hourly fuel flow rate-to-load ratio and the baseline value of the fuel flow rate-to-load ratio (or hourly and baseline GHR).
q = Number of hours used in fuel flow-to-load (or GHR) evaluation.

App. D § 2.1.7.2(h) (h) When the quarterly average load value used in the data analysis is greater than 50 MWe (or 500 klb steam per hour), the results of a quarterly fuel flow rate-to-load (or GHR) evaluation are acceptable and no further action is required if the quarterly average percentage difference (E_f) is no greater than 10.0 percent. When the arithmetic average of the hourly load values used in the data analysis is ≤ 50 MWe (or 500 klb steam per hour), the results of the analysis are acceptable if the value of E_f is no greater than 15.0 percent. For units that normally co-fire different types of fuel, if the GHR option is used, apply the test results to each fuel flowmeter system used during the quarter.

App. D § 2.1.7.3 2.1.7.3 Optional Data Exclusions

(a) If E_f is outside the limits in section 2.1.7.2(h) of this appendix, the owner or operator may re-examine the hourly fuel flow rate-to-load ratios (or GHRs) that were used for the data analysis and may identify and exclude fuel flow-to-load ratios or GHR values for any non-representative hours, provided that such data exclusions were not previously made under section 2.1.7.2(a) of this appendix. Specifically, the R_h or $(GHR)_h$ values for the following hours may be considered non-representative:

(1) For units that do not normally co-fire fuels, any hour in which the unit combusted another fuel in addition to the fuel measured by the fuel flowmeter being tested; or

(2) Any hour for which the load differed by more than + 15.0 percent from the load during either the preceding hour or the subsequent hour; or

(3) For units that normally co-fire different fuels, any hour in which the unit burned only one type of fuel; or

(4) Any hour for which the unit load was in the lower 25.0 percent of the range of operation, as defined in section 6.5.2.1 of appendix A to this part (unless operation in the lower 25.0 percent of the range is considered normal for the unit).

(b) After identifying and excluding all non-representative hourly fuel flow-to-load ratios or GHR values, analyze the quarterly fuel flow rate-to-load data a second time. If fewer than 168 hourly fuel flow-to-load ratio or GHR values remain after the allowable data exclusions, a fuel flow-to-load ratio or GHR analysis is not required for that quarter, and a one-quarter extension of the fuel flowmeter accuracy test deadline may be claimed.

App. D § 2.1.7.4 2.1.7.4 Consequences of Failed Fuel Flow-to-Load Ratio Test

(a) If E_f is outside the applicable limit in section 2.1.7.2(h) of this appendix (after analysis using any optional data exclusions under section 2.1.7.3 of this appendix), perform transmitter accuracy tests according to section 2.1.6.1 of this appendix for orifice-, nozzle-, and venturi-type flowmeters, or perform a fuel flowmeter accuracy test, in accordance with section 2.1.5.1 or 2.1.5.2

of this appendix, for each fuel flowmeter for which E_f is outside of the applicable limit. In addition, for an orifice-, nozzle-, or venturi-type fuel flowmeter, repeat the fuel flow-to-load ratio comparison of section 2.1.7.2 of this appendix using six to twelve hours of data following a passed transmitter accuracy test in order to verify that no significant corrosion has affected the primary element. If, for the abbreviated 6-to-12 hour test, the orifice-, nozzle-, or venturi-type fuel flowmeter is not able to meet the limit in section 2.1.7.2 of this appendix, then perform a visual inspection of the primary element according to section 2.1.6.4 of this appendix, and repair or replace the primary element, as necessary.

(b) Substitute for fuel flow rate, for any hour when that fuel is combusted, using the missing data procedures in section 2.4.2 of this appendix, beginning with the first hour of the calendar quarter following the quarter for which E_f was found to be outside the applicable limit and continuing until quality assured fuel flow data become available. Following a failed flow rate-to-load or GHR evaluation, data from the flowmeter shall not be considered quality assured until the hour in which all required flowmeter accuracy tests, transmitter accuracy tests, visual inspections and diagnostic tests have been passed. Additionally, a new value of R_{base} or $(GHR)_{base}$ shall be established no later than two fuel flowmeter QA operating quarters (as defined in § 72.2 of this chapter) after the quarter in which the required quality assurance tests are completed (note that for orifice-, nozzle-, or venturi-type fuel flowmeters, establish a new value of R_{base} or $(GHR)_{base}$ only if both a transmitter accuracy test and a primary element inspection have been performed).

App. D § 2.1.7.5

2.1.7.5 Test Results

Report the results of each quarterly flow rate-to-load (or GHR) evaluation, as determined from Equation D-1g, in the electronic quarterly report required under § 75.64. Table D-3 is provided as a reference on the type of information to be recorded under § 75.59 and reported under § 75.64.

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

Plant name:_____ State:____ ORIS code:_____ Unit/pipe ID #:_____ Fuel flowmeter system ID :___ Calendar quarter (1st, 2nd, 3rd, 4th) and year:_____ Range of operation: _____ to _____ MWe or klb steam/hr (indicate units)	
Reported Data Elements	
Baseline period	Quarterly analysis
Completion date and time of most recent QA sequence, i.e., primary element inspection and transmitter calibration (orifice-, nozzle-, and venturi-type flowmeters only). __/__/__ __:__	Number of hours excluded from quarterly average due to co-firing different fuels (where co-firing is not normal operation):_____ hrs.
Completion date and time of most recent flowmeter or accuracy test (all other flowmeters) __/__/__ __:__	Number of hours excluded from quarterly average due to single-fuel combustion (where co-firing is normal operation):_____ hrs.
Beginning date and time of baseline period __/__/__ __:__	Number of hours excluded from quarterly average due to ramping load:_____ hrs.
End date and time of baseline period __/__/__ __:__	Number of hours in the lower 25.0 percent of the range of operation excluded from quarterly average: _____hrs.
Average fuel flow rate_____ (100 scfh for gas and lb/hr for oil)	Number of hours included in quarterly average:_____ hrs.
	Quarterly percentage difference between hourly ratios and baseline ratio:_____ percent.
Average load;_____ (MWe or 1000 lb steam/hr)	Test result: pass, fail.
Baseline fuel flow-to-load ratio _____ Units of fuel flow-to-load:_____	
Baseline GHR: _____ Units of fuel flow-to-load:_____	
Number of hours excluded from baseline ratio or GHR due to ramping load: _____	
Number of hours in the lower 25.0 percent of the range of operation excluded from baseline ratio or GHR: _____hrs.	

App. D § 2.2

2.2 *Oil Sampling and Analysis*

Perform sampling and analysis of oil to determine the following fuel properties for each type of oil combusted by a unit: percentage of sulfur by weight in the oil; gross calorific value (GCV) of the oil; and, if necessary, the density of the oil. Use the sulfur content, density, and gross calorific value, determined under the provisions of this section, to calculate SO_2 mass emission rate and heat

input rate for each fuel using the applicable procedures of section 3 of this appendix. The designated representative may petition for reduced GCV and or density sampling under § 75.66 if the fuel combusted has a consistent and relatively non-variable GCV or density.

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

Parameter	Sampling technique/frequency	Value used in calculations (except for missing data hours)
Oil Sulfur Content	Daily manual sampling	1. Highest sulfur content from previous 30 daily samples; or 2. Actual daily value.
	Flow proportional/weekly composite	Actual measured value.
	In storage tank (after addition of fuel to tank)	1. Actual measured value; or 2. Highest of all sampled values in previous calendar year, unless a higher sample value is obtained;[1] or 3. Maximum value allowed by contract, unless a higher sample value is obtained.[1]
	As delivered (in delivery truck or barge).[1]	1. Highest of all sampled values in previous calendar year, unless a higher sample value is obtained;[1] or 2. Maximum value allowed by contract, unless a higher sample value is obtained.[1]
Oil Density	Daily manual sampling	1. Use the highest density from the previous 30 daily samples; or 2. Actual measured value.
	Flow proportional/weekly composite	Actual measured value.
	In storage tank (after addition of fuel to tank)	1. Actual measured value; or 2. Highest of all sampled values in previous calendar year, unless a higher sample value is obtained;[1] or 3. Maximum value allowed by contract, unless a higher sample value is obtained.[1]
	As delivered (in delivery truck or barge).[1]	1. Highest of all sampled values in previous calendar year, unless a higher sample value is obtained;[1] or 2. Maximum value allowed by contract, unless a higher sample value is obtained.[1]
Oil GCV	Daily manual sampling	1. Highest fuel GCV from the previous 30 daily samples; or 2. Actual measured value.
	Flow proportional/weekly composite	Actual measured value.
	In storage tank (after addition of fuel to tank)	1. Actual measured value; or 2. Highest of all sampled values in previous calendar year, unless a higher sample value is obtained;[1] or 3. Maximum value allowed by contract, unless a higher sample value is obtained.[1]
	As delivered (in delivery truck or barge).[1]	1. Highest of all sampled values in previous calendar year, unless a higher sample value is obtained;[1] or 2. Maximum value allowed by contract, unless a higher sample value is obtained.[1]

[1] Assumed values may only be used if sulfur content, gross calorific value, or density of each sample is no greater than the assumed value used to calculate emissions or heat input. If a higher sample value is obtained, use the results of that sample analysis as the new assumed value.

App. D § 2.2.1

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.

App. D § 2.2.2

2.2.2 [Reserved]

App. D § 2.2.3

2.2.3 Flow Proportional Sampling

Conduct flow proportional oil sampling or continuous drip oil sampling in accordance with ASTM D4177-95 (2000) ~~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_2 mass emission rates for each operating day represented by the composite sample. Calculate the hourly heat input rates for each operating day represented by the composite sample, using the actual gross calorific value from the composite sample.

App. D § 2.2.4

2.2.4 Manual Sampling

App. D § 2.2.4.1

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 D4057-95 (2000)~~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_2 emissions under section 3 of this appendix. Use either the gross calorific value measured from that day's sample or the highest GCV from the previous 30 days' samples to calculate heat input. If oil supplies with different sulfur contents are combusted on the same day, sample the highest sulfur fuel combusted that day.

App. D § 2.2.4.2

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 D4057-95 (2000)~~D4057-88~~, "Standard Practice for Manual Sampling of Petroleum and Petroleum Products" (incorporated by reference under § 75.6). Use the sulfur content and GCV value (and where required, the density) of either the most recent sample or one of the conservative assumed values described in section 2.2.4.3(c) of this appendix to calculate SO_2 mass emission rate. Calculate heat input rate using the gross calorific value from either:

(a) The most recent oil sample taken or

(b) One of the conservative assumed values described in section 2.2.4.3(c) of this appendix. Follow the applicable provisions in section 2.2.4.3(d) of this appendix, regarding the use of assumed values.

App. D § 2.2.4.3

2.2.4.3 Sampling from Each Delivery

App. D § 2.2.4.3(a)

(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.)

App. D § 2.2.4.3(b)

(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.

App. D § 2.2.4.3(c)

(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 D4057-95 (2000)~~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_2 mass emission rate using the sulfur content (and where required, the density) from one of the following conservative, assumed values, and calculate heat input using the gross calorific value from one of the assumed values:

(1) The highest value sampled during the previous calendar year (this option is allowed for any consistent fuel which comes from a single source whether or not the fuel is supplied under a contractual agreement) or

(2) The maximum value indicated in the contract with the fuel supplier. Continue to use this assumed contract value unless and until the actual sampled sulfur content, density, or gross calorific value of a delivery exceeds the assumed value.

App. D § 2.2.4.3(d)

(d) Continue using the assumed value(s), so long as the sample results do not exceed the assumed value(s). However, if the actual sampled sulfur content, gross calorific value, or density of an oil sample is greater than the assumed value for that parameter, then, consistent with section 2.3.7 of this appendix, begin to use the actual sampled value for sulfur content, gross calorific value, or density of fuel to calculate SO_2 mass emission rate or heat input rate. Consider the sampled value to be the new assumed sulfur content, gross calorific value, or density. Continue using this new assumed value to calculate SO_2 mass emission rate or heat input rate unless and until: it is superseded by a higher value from an oil sample; or (if applicable) it is superseded by a new contract in which case the new contract value becomes the assumed value at the time the fuel specified under the new contract begins to be combusted in the unit; or (if applicable) both the calendar year in which the sampled value exceeded the assumed value and the subsequent calendar year have elapsed.

App. D § 2.2.5

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.~~ For each oil sample that is taken on-site at the affected facility, split and label the sample and maintain a portion (at least 200 cc) of it throughout the calendar year and in all cases for not less than 90 calendar days after the end of the calendar year allowance accounting period. This requirement does not apply to oil samples taken from the fuel supplier's storage container, as described in section 2.2.4.3 of this appendix. Analyze oil samples for percent sulfur content by weight in accordance with ASTM D129-00, "Standard Test Method for Sulfur in Petroleum Products (General Bomb Method)," ASTM D1552-01~~D1552-90~~, "Standard Test Method for Sulfur in Petroleum Products (High Temperature Method)," ASTM D2622-98~~D2622-92~~, "Standard Test Method for Sulfur in Petroleum Products by X-Ray Spectrometry," or ASTM D4294-98~~D4294-90~~, "Standard Test Method for Sulfur in Petroleum Products by Energy-Dispersive X-Ray Fluorescence Spectroscopy" (incorporated by reference under § 75.6).

App. D § 2.2.6

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 D287-92 (2000)e1 ~~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 D1217-93 (1998)~~D1217-91~~, "Standard Test Method for Density and Relative Density (Specific Gravity) of Liquids by Bingham Pycnometer," ASTM D1481-93 (1997) ~~D1481-91~~, "Standard Test Method for Density and Relative Density (Specific Gravity) of Viscous Materials by Lipkin Bicapillary," ASTM D1480-93 (1997)~~D1480-91~~, "Standard Test Method for Density and Relative Density (Specific Gravity) of Viscous Materials by Bingham Pycnometer," ASTM D1298-99~~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 D4052-96 (2002) e1 ~~D4052-91~~, "Standard Test Method for Density and Relative Density of Liquids by Digital Density Meter" (incorporated by reference under § 75.6).

App. D § 2.2.7

2.2.7 Analyze oil samples to determine the heat content of the fuel. Determine oil heat content in accordance with ASTM D240-00 ~~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)'~~ ASTM D4809-00, "Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method), or ~~ASTM D2015-91, "Standard Test Method for Gross Calorific Value of Coal and Coke by the Adiabatic Bomb Calorimeter~~" ASTM D5865-01ae1, "Standard Test Method for Gross Calorific Value of Coal and Coke" (incorporated by reference under § 75.6) or any other procedures listed in section 5.5 of appendix F of this part.

App. D § 2.2.8

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.

App. D § 2.3

2.3 SO_2 Emissions from Combustion of Gaseous Fuels

App. D § 2.3(a)

(a) Account for the hourly SO_2 mass emissions due to combustion of gaseous fuels for each hour when gaseous fuels are combusted by the unit using the procedures in this section.

App. D § 2.3(b)

(b) The procedures in sections 2.3.1 and 2.3.2 of this appendix, respectively, may be used to determine SO_2 mass emissions from combustion of pipeline natural gas and natural gas, as defined in § 72.2 of this chapter. The procedures in section 2.3.3 of this appendix may be used to account for SO_2 mass emissions from any gaseous fuel combusted by a unit. For each type of gaseous fuel, the appropriate sampling frequency and the sulfur content and GCV values used for calculations of SO_2 mass emission rates are summarized in the following Table D-5.

TABLE D-5. -- GAS SULFUR AND GCV VALUES USED IN CALCULATIONS FOR VARIOUS FUEL TYPES

Parameter	Fuel type and sampling frequency	Value used in calculations (except for missing data hours)
Gas Total Sulfur Content	Pipeline Natural Gas with total sulfur content less than or equal to 0.5 grains/100scf when using the provisions of section 2.3.1 to determine SO_2 mass emissions * Sampling is not required if a valid contract or tariff sheet is used to qualify. * If fuel sampling and analysis is used to qualify, sample annually and whenever the fuel supply source changes.	1. If a contract or tariff sheet is used to qualify, use 0.0006 lb/mmBtu 2. If fuel sampling and analysis is used to qualify, use 0.0006 lb/mmBtu, provided that the results of the required annual samples do not exceed 0.5 grains/100 scf of total sulfur. If the results of an annual sample exceed 0.5 grains/100 scf, re-classify the fuel as appropriate and determine the SO_2 emission rate to be used in the calculations, using the applicable procedures in section 2.3.2 or 2.3.3 of this appendix
	Natural Gas with total sulfur content less than or equal to 20.0 grains /100scf * Sampling is not required if a valid contract or tariff sheet is used to qualify. * If fuel sampling and analysis is used to qualify, sample annually and whenever the fuel supply source changes.	Default SO_2 emission rate calculated from Eq. D-1h, using either: 1. The maximum total sulfur content specified in the fuel contract or tariff sheet, if a contract or tariff sheet is used to qualify; or 2. The total sulfur content, based on the most recent fuel sampling and analysis. If multiple samples are taken, the results may be averaged before using Equation D-1h.
	Any gaseous fuel transmitted by pipeline, having a "low sulfur variability", as shown under section 2.3.6 of this appendix. * Either sample daily or, if Eq. D-1h is used to calculate a default SO_2 emission rate, sample annually.	* If daily sampling is performed, use either: 1. Actual value from the daily sample; or 2. Highest value from previous 30 samples. * If the option to use Eq. D-1h is selected, use a default SO_2 emission rate, calculated using the higher of: 1. The 90th percentile value of the total sulfur content, obtained in the 720-hr demonstration under section 2.3.6; or 2. The actual total sulfur content from the most recent annual sample. If multiple samples are taken, the results may be averaged before using Equation D-1h.
	Any gaseous fuel transmitted by pipeline, having a maximum total sulfur content < 20 grains/100 scf and "high sulfur variability", as shown under section 2.3.6 of this appendix. * Either sample hourly or, if Eq. D-1h is used to calculate a default SO_2 emission rate, sample annually.	* If hourly sampling is performed, use the actual hourly value * If the option to use Eq. D-1h is selected, use a default SO_2 emission rate, calculated using the higher of: 1. The maximum value of the total sulfur content, obtained in the 720-hr demonstration under section 2.3.6; or 2. The actual total sulfur content from the most recent annual sample. If multiple samples are taken, the results may be averaged before using Equation D-1h.

(cont.)

TABLE D-5. -- GAS SULFUR AND GCV VALUES USED IN CALCULATIONS FOR VARIOUS FUEL TYPES (cont.)

Parameter	Fuel type and sampling frequency	Value used in calculations (except for missing data hours)
Gas Total Sulfur Content (cont.)	Any gaseous fuel transmitted by pipeline, having a maximum total sulfur content > 20 grains/100 scf and "high sulfur variability," as shown under section 2.3.6 of this appendix. * Sample hourly	Actual hourly sulfur content of the gas
	Any gaseous fuel delivered in shipments or lots * Sample each lot or shipment.	1. Actual total sulfur content from most recent shipment; or 2. Highest total sulfur content from previous year's samples, unless a higher value is obtained in a sample[1] ; or 3. Maximum total sulfur content value allowed by contract, unless a higher value is obtained in a sample.[1]
Gas GCV	Pipeline Natural Gas * Sample monthly	1. GCV from most recent monthly sample (with > 48 operating hours in the month); 2. Maximum GCV from contract, unless a higher value is obtained in a monthly sample;[1] or 3. Highest GCV from previous year's samples, unless a higher value is obtained in a monthly sample.[1]
	Natural Gas * Sample monthly	1. GCV from most recent monthly sample (with > 48 operating hours in the month); 2. Maximum GCV from contract;[1] or 3. Highest GCV from previous year's samples.[1]
	Any gaseous fuel delivered in shipments or lots * Sample each lot or shipment	1. Actual GCV from most recent shipment or lot; 2. Highest GCV from previous year's samples, unless a higher value is obtained in a sample;[1] or 3. Maximum GCV value allowed by contract, unless a higher value is obtained in a sample.[1]
	Any gaseous fuel transmitted by pipeline and having a demonstrated "low GCV variability" using the provisions of section 2.3.5 * Sample monthly	1. GCV from most recent monthly sample (with > 48 operating hours in the month); or 2. Highest GCV from previous year's samples, unless a higher value is obtained in a monthly sample.[1]
	Any gaseous fuel not demonstrated to have a "low GCV variability" under section 2.3.5 * Sample daily or hourly. (Note that the use of an on-line GCV calorimeter or gas chromatograph is allowed).	Actual daily or hourly GCV of the gas.

[1] Assumed sulfur content and GCV values (i.e., contract values or highest values from previous year) may only continue to be used if the sulfur content or GCV of each sample is no greater than the assumed value used to calculate SO_2 emissions or heat input. If a higher sample value is obtained, use the results of that sample analysis as the new assumed value.

App. D § 2.3.1

2.3.1 Pipeline Natural Gas Combustion

The owner or operator may determine the SO_2 mass emissions from the combustion of a fuel that meets the definition of pipeline natural gas, in § 72.2 of this chapter, using the procedures of this section.

App. D § 2.3.1.1

2.3.1.1 SO_2 Emission Rate

For a fuel that meets the definition of pipeline natural gas under § 72.2 of this chapter, the owner or operator may determine the SO_2 mass emissions using either a default SO_2 emission rate of 0.0006 lb/mmBtu and the procedures of this section, the procedures in section 2.3.2 for natural gas, or the procedures of section 2.3.3 for any gaseous fuel. For each affected unit using the default rate of 0.0006 lb/mmBtu, the owner or operator must document that the fuel combusted is actually pipeline natural gas, using the procedures in section 2.3.1.4 of this appendix.

App. D § 2.3.1.2

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.

App. D § 2.3.1.3

2.3.1.3 SO_2 Hourly Mass Emission Rate and Hourly Mass Emissions

For pipeline natural gas combustion, calculate the SO_2 mass emission rate, in lb/hr, using Equation D-5 in section 3.3.2 of this appendix (when the default SO_2 emission rate is used) or Equation D-4 (if daily or hourly fuel sampling is used). Then, use the calculated SO_2 mass emission rate and the unit operating time to determine the hourly SO_2 mass emissions from pipeline natural gas combustion, in lb, using Equation D-12 in section 3.5.1 of this appendix.

App. D § 2.3.1.4

2.3.1.4 Documentation that a Fuel is Pipeline Natural Gas

App. D § 2.3.1.4(a)

(a) A fuel may initially qualify as pipeline natural gas, if information is provided in the monitoring plan required under § 75.53, demonstrating that the definition of pipeline natural gas in § 72.2 of this chapter has been met. The information must demonstrate that the fuel meets either the percent methane or GCV requirement and has a total sulfur content of 0.5 grains/100scf or less. The demonstration must be made using one of the following sources of information:

(1) The gas quality characteristics specified by a purchase contract, tariff sheet, or by a pipeline transportation contract; or

(2) Historical fuel sampling data for the previous 12 months, documenting the total sulfur content of the fuel and the GCV and/or percentage by volume of methane. The results of all sample analyses obtained by or provided to the owner or operator in the previous 12 months shall be used in the demonstration, and each sample result must meet the definition of pipeline natural gas in § 72.2 of this chapter~~; or~~, except where the results of at least 100 daily (or more frequent) total sulfur samples are provided by the fuel supplier. In that case you may convert these data to monthly averages and then if, for each month, the average total sulfur content is 0.5 grains/100 scf or less, and if the GCV or percent methane requirement is also met, the fuel qualifies as pipeline natural gas. Alternatively, the fuel qualifies as pipeline natural gas if the GCV or percent methane requirement is met and if ≥ 98 percent of the 100 (or more) samples have a total sulfur content of 0.5 grains/100 scf or less; or

(3) If the requirements of paragraphs (a)(1) and (a)(2) of this section cannot be met, a fuel may initially qualify as pipeline natural gas if at least one representative sample of the fuel is obtained and analyzed for total sulfur content and for either the gross calorific value (GCV) or percent methane, and the results of the sample analysis show that the fuel meets the definition of pipeline natural gas in § 72.2 of this chapter. Use the sampling methods specified in sections 2.3.3.1.2 and 2.3.4 of this appendix. The required fuel sample may be obtained and analyzed by the owner or operator, by an independent laboratory, or by the fuel supplier. If multiple samples are taken, each sample must meet the definition of pipeline natural gas in § 72.2 of this chapter.;

App. D § 2.3.1.4(b)

(b) If the results of the fuel sampling under paragraph (a)(2) or (a)(3) of this section show that the fuel does not meet the definition of pipeline natural gas in § 72.2 of this chapter, but those results are believed to be anomalous, the owner or operator may document the reasons for believing this in the monitoring plan for the unit, and may immediately perform additional sampling. In such cases, a minimum of three additional samples must be obtained and analyzed, and the results of each sample analysis must meet the definition of pipeline natural gas.

App. D § 2.3.1.4(c)

(c) If several affected units are supplied by a common source of gaseous fuel, a single sampling result may be applied to all of the units and it is not necessary to obtain a separate sample for each unit, provided that the composition of the fuel is not altered by blending or mixing it with other gaseous fuel(s) when it is transported from the sampling location to the affected units. For the purposes of this paragraph, the term "other gaseous fuel(s)" excludes compounds such as mercaptans when they are added in trace quantities for safety reasons.

App. D § 2.3.1.4(d)

(d) If the results of fuel sampling and analysis under paragraph (a)(2), (a)(3), or (b) of this section show that the fuel does not qualify as pipeline natural gas, proceed as follows:

(1) If the fuel still qualifies as natural gas under section 2.3.2.4 of this appendix, re-classify the fuel as natural gas and determine the appropriate default SO_2 emission rate for the fuel, according to section 2.3.2.1.1 of this appendix; or

(2) If the fuel does not qualify either as pipeline natural gas or natural gas, re-classify the fuel as "other gaseous fuel" and implement the procedures of section 2.3.3 of this appendix, within 180 days of the end of the quarter in which the disqualifying sample was taken. In addition, the owner or operator shall use Equation D-1h in this appendix to calculate a default SO_2 emission rate for the fuel, based on the results of the sample analysis that exceeded 20 grains/100 scf of total sulfur, and shall use that default emission rate to report SO_2 mass emissions under this part until section 2.3.3 of this appendix has been fully implemented.

App. D § 2.3.1.4(e)

(e) If a fuel qualifies as pipeline natural gas based on the specifications in a fuel contract or tariff sheet, no additional, on-going sampling of the fuel's total sulfur content is required, provided that the contract or tariff sheet is current, valid and representative of the fuel combusted in the unit. If the fuel qualifies as pipeline natural gas based on fuel sampling and analysis, on-going sampling of the fuel's sulfur content is required annually and whenever the fuel supply source changes. For the purposes of this paragraph, (e), sampling "annually" means that at least one sample is taken in each calendar year. If the results of at least 100 daily (or more frequent) total sulfur samples have been provided by the fuel supplier since the last annual assessment of the fuel's sulfur content, the data may be used to satisfy the annual sampling requirement for the current year. If this option is chosen, all of the data provided by the fuel supplier shall be used. First, convert the data to monthly averages. Then, if, for each month, the average total sulfur content is 0.5 grains/100 scf or less, and if the GCV or percent methane requirement is also met, the fuel qualifies as pipeline natural gas. Alternatively, the fuel qualifies as pipeline natural gas if the GCV or percent methane requirement is met and if the analysis of the100 (or more) total sulfur samples since the last annual assessment shows that ≥ 98 percent of the samples have a total sulfur content of 0.5 grains/100 scf or less. The effective date of the annual total sulfur sampling requirement is January 1, 2003.

App. D § 2.3.1.4(f)

(f) On-going sampling of the GCV of the pipeline natural gas is required under section 2.3.4.1 of this appendix.

App. D § 2.3.1.4(g)

(g) For units that are required to monitor and report NO_x mass emissions and heat input under subpart H of this part, but which are not affected units under the Acid Rain Program, the owner or operator is exempted from the requirements in paragraphs (a) and (e) of this section to document the total sulfur content of the pipeline natural gas.

App. D § 2.3.2

2.3.2 Natural Gas Combustion

The owner or operator may determine the SO_2 mass emissions from the combustion of a fuel that meets the definition of natural gas, in § 72.2 of this chapter, using the procedures of this section.

App. D § 2.3.2.1

2.3.2.1 SO_2 Emission Rate

The owner or operator may account for SO_2 emissions either by using a default SO_2 emission rate, as determined under section 2.3.2.1.1 of this appendix, or by daily sampling of the gas sulfur content using the procedures of section 2.3.3 of this appendix. For each affected unit using a default SO_2 emission rate, the owner or operator must provide documentation that the fuel combusted is actually natural gas according to the procedures in section 2.3.2.4 of this appendix.

App. D § 2.3.2.1.1

2.3.2.1.1 In lieu of daily sampling of the sulfur content of the natural gas, the owner or operator may either use the total sulfur content specified in a contract or tariff sheet as the SO_2 default emission rate or may calculate the default SO_2 emission rate based on fuel sampling results, using Equation D-1h. In Equation D-1h, the total sulfur content and GCV values shall be determined in accordance with Table D-5 of this appendix. Round off the calculated SO_2 default emission rate to the nearest 0.0001 lb/mmBtu.

$$ER = \left[\frac{2.0}{7000}\right] \times \left[10^6\right] \times \left[\frac{S_{total}}{GCV}\right]$$

(Eq. D-1h)

Where:
ER = Default SO_2 emission rate for natural gas combustion, lb/mmBtu.
S_{total} = Total sulfur content of the natural gas, gr/100scf.
GCV = Gross calorific value of the natural gas, Btu/100scf.
7000 = Conversion of grains/100scf to lb/100scf.
2.0 = Ratio of lb SO_2/lb S.
10^6 = Conversion factor (Btu/mmBtu).

App. D § 2.3.2.1.2

2.3.2.1.2 [Reserved]

App. D § 2.3.2.2

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.

App. D § 2.3.2.3

2.3.2.3 SO_2 Mass Emission Rate and Hourly Mass Emissions

For natural gas combustion, calculate the SO_2 mass emission rate, in lb/hr, using Equation D-5 in section 3.3.2 of this appendix, when the default SO_2 emission rate is used. Then, use the calculated SO_2 mass emission rate and the unit operating time to determine the hourly SO_2 mass emissions from natural gas combustion, in lb, using Equation D-12 in section 3.5.1 of this appendix.

App. D § 2.3.2.4

2.3.2.4 Documentation that a Fuel Is Natural Gas

App. D § 2.3.2.4(a)

(a) A fuel may initially qualify as natural gas, if information is provided in the monitoring plan required under § 75.53, demonstrating that the definition of natural gas in § 72.2 of this chapter has been met. The information must demonstrate that the fuel meets either the percent methane or GCV requirement and has a total sulfur content of 20.0 grains/100 scf or less. This demonstration must be made using one of the following sources of information:

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

(2) Historical fuel sampling data for the previous 12 months, documenting the total sulfur content of the fuel and the GCV and/or percentage by volume of methane. The results of all sample analyses obtained by or provided to the owner or operator in the previous 12 months shall be used in the demonstration, and each sample result must meet the definition of natural gas in § 72.2 of this chapter; or

(3) If the requirements of paragraphs (a)(1) and (a)(2) of this section cannot be met, a fuel may initially qualify as natural gas if at least one representative sample of the fuel is obtained and analyzed for total sulfur content and for either the gross calorific value (GCV) or percent methane, and the results of the sample analysis show that the fuel meets the definition of natural gas in § 72.2 of this chapter. Use the sampling methods specified in sections 2.3.3.1.2 and 2.3.4 of this appendix. The required fuel sample may be obtained and analyzed by the owner or operator, by an independent laboratory, or by the fuel supplier. If multiple samples are taken, each sample must meet the definition of natural gas in § 72.2 of this chapter.

App. D § 2.3.2.4(b) (b) If the results of the fuel sampling under paragraph (a)(2) or (a)(3) of this section show that the fuel does not meet the definition of natural gas in § 72.2 of this chapter, but those results are believed to be anomalous, the owner or operator may document the reasons for believing this in the monitoring plan for the unit, and may immediately perform additional sampling. In such cases, a minimum of three additional samples must be obtained and analyzed, and the results of each sample analysis must meet the definition of natural gas.

App. D § 2.3.2.4(c) (c) If several affected units are supplied by a common source of gaseous fuel, a single sampling result may be applied to all of the units and it is not necessary to obtain a separate sample for each unit, provided that the composition of the fuel is not altered by blending or mixing it with other gaseous fuel(s) when it is transported from the sampling location to the affected units. For the purposes of this paragraph, the term "other gaseous fuel(s)" excludes compounds such as mercaptans when they are added in trace quantities for safety reasons.

App. D § 2.3.2.4(d) (d) If the results of fuel sampling and analysis under paragraph (a)(2), (a)(3), or (b) of this section show that the fuel does not qualify as natural gas, the owner or operator shall re-classify the fuel as "other gaseous fuel" and shall implement the procedures of section 2.3.3 of this appendix, within 180 days of the end of the quarter in which the disqualifying sample was taken. In addition, the owner or operator shall use Equation D-1h in this appendix to calculate a default SO_2 emission rate for the fuel, based on the results of the sample analysis that exceeded 20 grains/100 scf of total sulfur, and shall use that default emission rate to report SO_2 mass emissions under this part until section 2.3.3 of this appendix has been fully implemented.

App. D § 2.3.2.4(e) (e) If a fuel qualifies as natural gas based on the specifications in a fuel contract or tariff sheet, no additional, on-going sampling of the fuel's total sulfur content is required, provided that the contract or tariff sheet is current, valid and representative of the fuel combusted in the unit. If the fuel qualifies as natural gas based on fuel sampling and analysis, the owner or operator shall sample the fuel for total sulfur content at least annually and when the fuel supply source changes. For the purposes of this paragraph, (e), sampling "annually" means that at least one sample is taken in each calendar year. The effective date of the annual total sulfur sampling requirement is January 1, 2003.

App. D § 2.3.2.4(f) (f) On-going sampling of the GCV of the natural gas is required under section 2.3.4.2 of this appendix.

App. D § 2.3.2.4(g) (g) For units that are required to monitor and report NO_x mass emissions and heat input under subpart H of this part, but which are not affected units under the Acid Rain Program, the owner or operator is exempted from the requirements in paragraphs (a) and (e) of this section to document the total sulfur content of the natural gas.

App. D § 2.3.3 2.3.3 SO_2 Mass Emissions From Any Gaseous Fuel

The owner or operator of a unit may determine SO_2 mass emissions using this section for any gaseous fuel (including fuels such as refinery gas, landfill gas, digester gas, coke oven gas, blast furnace gas, coal-derived gas, producer gas or any other gas which may have a variable sulfur content).

App. D § 2.3.3.1 2.3.3.1 Sulfur Content Determination

App. D § 2.3.3.1.1

2.3.3.1.1 Analyze the total sulfur content of the gaseous fuel in grains /100 scf, at the frequency specified in Table D-5 of this appendix. That is: for fuel delivered in discrete shipments or lots, sample each shipment or lot. For fuel transmitted by pipeline, sample hourly unless a demonstration is provided under section 2.3.6 of this appendix showing that the gaseous fuel qualifies for less frequent (i.e., daily or annual) sampling. If daily sampling is required, determine the sulfur content using either manual sampling or a gas chromatograph. If hourly sampling is required, determine the sulfur content using a gas chromatograph. For units that are required to monitor and report NO_x mass emissions and heat input under subpart H of this part, but which are not affected units under the Acid Rain Program, the owner or operator is exempted from the requirements of this section to document the total sulfur content of the gaseous fuel.

App. D § 2.3.3.1.2

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 (1999), "Standard Test Method for Total Sulfur in Fuel Gases," ASTM D4468-85 (2000) ~~(Reapproved 1989)~~ "Standard Test Method for Total Sulfur in Gaseous Fuels by Hydrogenolysis and Radiometric Colorimetry," ASTM D5504-01 ~~D5504-94~~ "Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence," ASTM D6667-04 "Standard Test Method for Determination of Total Volatile Sulfur in Gaseous Hydrocarbons and Liquified Petroleum Gases by Ultraviolet Fluorescence," or ASTM D3246-96 ~~D3246-81 (Reapproved 1987)~~ "Standard Test Method for Sulfur in Petroleum Gas By Oxidative Microcoulometry" (incorporated by reference under § 75.6).

App. D § 2.3.3.1.3

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.

App. D § 2.3.3.1.4

2.3.3.1.4 Results of all sample analyses must be available no later than thirty calendar days after the sample is taken.

App. D § 2.3.3.2

2.3.3.2 SO_2 Mass Emission Rate

Calculate the SO_2 mass emission rate for the gaseous fuel, in lb/hr, using Equation D-4 or D-5 (as applicable) in section 3.3.1 of this appendix. Equation D-5 may only be used if a demonstration is performed under section 2.3.6 of this appendix, showing that the fuel qualifies to use a default SO_2 emission rate to account for SO_2 mass emissions under this part. Use the appropriate sulfur content or default SO_2 emission rate in Equation D-4 or D-5, as specified in Table D-5 of this appendix. If the fuel qualifies to use Equation D-5, the default SO_2 emission rate shall be calculated using Equation D-1h in section 2.3.2.1.1 of this appendix, replacing the words "natural gas" in the equation nomenclature with the words, "gaseous fuel." In all cases, for reporting purposes, apply the results of the required periodic total sulfur samples in accordance with the provisions of section 2.3.7 of this appendix.

App. D § 2.3.3.3

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.

App. D § 2.3.4

2.3.4 Gross Calorific Values for Gaseous Fuels

Determine the GCV of each gaseous fuel at the frequency specified in this section, using one of the following methods: ASTM D1826-94 (1998) ~~D1826-88~~, ASTM D3588-98 ~~D3588-91~~, ASTM D4891-89 (2001), GPA Standard 2172-1996 ~~86~~ "Calculation of Gross Heating Value, Relative Density and Compressibility Factor for Natural Gas Mixtures from Compositional Analysis," or GPA Standard 2261-1999 ~~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.

App. D § 2.3.4.1

2.3.4.1 GCV of Pipeline Natural Gas

Determine the GCV of fuel that is pipeline natural gas, as defined in § 72.2 of this chapter, at least once per calendar month. For GCV used in calculations use the specifications in Table D-5: either the value from the most recent monthly sample, the highest value specified in a contract or tariff sheet, or the highest value from the previous year. The fuel GCV value from the most recent monthly sample shall be used for any month in which that value is higher than a contract limit. If a unit combusts pipeline natural gas for less than 48 hours during a calendar month, the sampling and analysis requirement for GCV is waived for that calendar month. The preceding waiver is limited by the condition that at least one analysis for GCV must be performed for each quarter the unit operates for any amount of time. If multiple GCV samples are taken and analyzed in a particular month, the GCV values from all samples shall be averaged arithmetically to obtain the monthly GCV. Then, for the purposes of implementing paragraph (c) in section 2.3.7 of this appendix, consider the latest date of any of the individual GCV samples used in the monthly average to be the "date on which the sample was taken".

App. D § 2.3.4.2

2.3.4.2 GCV of Natural Gas

Determine the GCV of fuel that is natural gas, as defined in § 72.2 of this chapter, on a monthly basis, in the same manner as described for pipeline natural gas in section 2.3.4.1 of this appendix.

App. D § 2.3.4.3

2.3.4.3 GCV of Other Gaseous Fuels

For gaseous fuels other than natural gas or pipeline natural gas, determine the GCV as specified in section 2.3.4.3.1, 2.3.4.3.2 or 2.3.4.3.3, as applicable. For reporting purposes, apply the results of the required periodic GCV samples in accordance with the provisions of section 2.3.7 of this appendix.

App. D § 2.3.4.3.1

2.3.4.3.1 For a gaseous fuel that is delivered in discrete shipments or lots, determine the GCV for each shipment or lot. The determination may be made by sampling each delivery or by sampling the supply tank after each delivery. For sampling of each delivery, use the highest GCV in the previous year's samples. For sampling from the tank after each delivery, use either the most recent GCV sample, the maximum GCV specified in the fuel contract or tariff sheet, or the highest GCV from the previous year's samples.

App. D § 2.3.4.3.2

2.3.4.3.2 For any gaseous fuel that does not qualify as pipeline natural gas or natural gas, which is not delivered in shipments or lots, and for which the owner or operator performs the 720 hour test under section 2.3.5 of this appendix, if the results of the test demonstrate that the gaseous fuel has a low GCV variability, determine the GCV at least monthly (as described in section 2.3.4.1 of this appendix). In calculations of hourly heat input for a unit, use either the most recent monthly sample, the maximum GCV specified in the fuel contract or tariff sheet, or the highest fuel GCV from the previous year's samples.

App. D § 2.3.4.3.3

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.

App. D § 2.3.5 2.3.5 Demonstration of Fuel GCV Variability

App. D § 2.3.5(a) (a) This optional demonstration may be made for any fuel which does not qualify as pipeline natural gas or natural gas, and is not delivered only in shipments or lots. The demonstration data may be used to show that monthly sampling of the GCV of the gaseous fuel or blend is sufficient, in lieu of daily GCV sampling.

App. D § 2.3.5(b) (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.

App. D § 2.3.5(c) (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.

App. D § 2.3.6 2.3.6 Demonstration of Fuel Sulfur Variability

App. D § 2.3.6(a) (a) This demonstration may be made for any fuel which does not qualify as pipeline natural gas or natural gas, and is not delivered only in shipments or lots. The results of the demonstration may be used to show that daily sampling for sulfur in the fuel is sufficient, rather than hourly sampling. The procedures in this section may also be used to demonstrate that a particular gaseous fuel qualifies to use a default SO_2 emission rate (calculated using Equation D-1h in section 2.3.2.1.1 of this appendix) for the purpose of reporting hourly SO_2 mass emissions under this part. To make this demonstration, proceed as follows. Provide a minimum of 720 hours of data, indicating the total sulfur content of the gaseous fuel (in gr/100 scf). The demonstration data shall be obtained using either manual hourly sampling or an on-line gas chromatograph (GC) capable of determining fuel total sulfur content on an hourly basis. For gaseous fuel produced by a variable process, the data shall be representative of all process operating conditions including seasonal or annual variations which may affect fuel sulfur content.

App. D § 2.3.6(b) (b) If the data are collected with an on-line GC, reduce the data to hourly average values of the total sulfur content of the fuel. If manual hourly sampling is used, the results of each hourly sample analysis shall be the total sulfur value for that hour. Express all hourly average values of total sulfur content in units of grains/100 scf. Use all of the hourly average values of total sulfur content in grains/100 scf to calculate the mean value and the standard deviation. Also determine the 90th percentile and maximum hourly values of the total sulfur content for the data set. If the standard deviation of the hourly values from the mean does not exceed 5.0 grains/100 scf, the fuel has a low sulfur variability. If the standard deviation exceeds 5.0 grains/100 scf, the fuel has a high sulfur variability. Based on the results of this determination, establish the required sampling frequency and SO_2 mass emissions methodology for the gaseous fuel, as follows:

(1) If the gaseous fuel has a low sulfur variability (irrespective of the total sulfur content), the owner or operator may either perform daily sampling of the fuel's total sulfur content using manual sampling or a GC, or may report hourly SO_2 mass emissions data using a default SO_2 emission rate calculated by substituting the 90th percentile value of the total sulfur content in Equation D-1h.

(2) If the gaseous fuel has a high sulfur variability, but the maximum hourly value of the total sulfur content does not exceed 20 grains/100 scf, the owner or operator may either perform

hourly sampling of the fuel's total sulfur content using an on-line GC, or may report hourly SO_2 mass emissions data using a default SO_2 emission rate calculated by substituting the maximum value of the total sulfur content in Equation D-1h.

(3) If the gaseous fuel has a high sulfur variability and the maximum hourly value of the total sulfur content exceeds 20 grains/100 scf, the owner or operator shall perform hourly sampling of the fuel's total sulfur content, using an on-line GC.

(4) Any gaseous fuel under paragraph (b)(1) or (b)(2) of this section, for which the owner or operator elects to use a default SO_2 emission rate for reporting purposes is subject to the annual total sulfur sampling requirement under section 2.3.2.4 (e) of this appendix.

App. D § 2.3.7

2.3.7 *Application of Fuel Sampling Results*

For reporting purposes, apply the results of the required periodic fuel samples described in Tables D-4 and D-5 of this appendix as follows. Use Equation D-1h to recalculate the SO_2 emission rate, as necessary.

(a) For daily samples of total sulfur content or GCV:

(1) If the actual value is to be used in the calculations, apply the results of each daily sample to all hours in the day on which the sample is taken; or

(2) If the highest value in the previous 30 daily samples is to be used in the calculations, apply that value to all hours in the current day. If, for a particular unit, fewer than 30 daily samples have been collected, use the highest value from all available samples until 30 days of historical sampling results have been obtained.

(b) For annual samples of total sulfur content:

(1) For pipeline natural gas, use the results of annual sample analyses in the calculations only if the results exceed 0.5 grains/100 scf. In that case, if the fuel still qualifies as natural gas, follow the procedures in paragraph (b)(2) of this section. If the fuel does not qualify as natural gas, the owner or operator shall implement the procedures in section 2.3.3 of this appendix, in the time frame specified in sections 2.3.1.4 (d) and 2.3.2.4 (d) of this appendix;

(2) For natural gas, apply the results of the most recent sample, beginning at the date of the sample;

(3) For other gaseous fuels with an annual sampling requirement under section 2.3.6 (b)(4) of this appendix, use the sample results in the calculations only if the results exceed the 90th percentile value or maximum value (as applicable) from the 720-hour demonstration of fuel sulfur content and variability under section 2.3.6 of this appendix.

(c) For monthly samples of the fuel GCV:

(1) If the actual value is to be used in the calculations, apply the results of the most recent sample, starting from the date on which the sample was taken; or

(2) If an assumed value (contract maximum or highest value from previous year's samples) is to be used in the calculations, apply the assumed value to all hours in each month of the quarter unless a higher value is obtained in a monthly GCV sample. In that case, use the sampled value, starting from the date on which the sample was taken. Consider the sample results to be the new assumed value. Continue using the new assumed value unless and until it is superseded by a higher value from a subsequent monthly sample; or (if applicable) it is superseded by a new contract in which case the new contract value becomes the assumed value at the time the fuel specified under the new contract begins to be combusted in the unit; or (if applicable) both the calendar year in which the sampled value exceeded the assumed value and the subsequent calendar year have elapsed.

(d) For samples of gaseous fuel delivered in shipments or lots:

(1) If the actual value for the most recent shipment is to be used in the calculations, apply the results of the most recent sample, from the date on which the sample was taken until the date on which the next sample is taken; or

(2) If an assumed value (contract maximum or highest value from previous year's samples) is to be used in the calculations, apply the assumed value unless a higher value is obtained in a sample of a shipment. In that case, use the sampled value, starting from the date on which the sample was taken. Consider the sample results to be the new assumed value. Continue using the new assumed value unless and until: it is superseded by a higher value from a sample of a subsequent shipment; or (if applicable) it is superseded by a new contract in which case the new contract value becomes the assumed value at the time the fuel specified under the new contract

begins to be combusted in the unit; or (if applicable) both the calendar year in which the sampled value exceeded the assumed value and the subsequent calendar year have elapsed.

(e) When the owner or operator elects to use assumed values in the calculations, the results of periodic samples of sulfur content and GCV which show that the assumed value has not been exceeded need not be reported. Keep these sample results on file, in a format suitable for inspection.

(f) Notwithstanding the requirements of paragraphs (b) through (d) of this section, in cases where the sample results are provided to the owner or operator by the supplier of the fuel, the owner or operator shall begin using the sampling results on the date of receipt of those results, rather than on the date that the sample was taken.

App. D § 2.4

2.4 Missing Data Procedures

When data from the procedures of this part are not available, provide substitute data using the following procedures.

App. D § 2.4.1

2.4.1 Missing Data for Oil and Gas Samples

When fuel sulfur content, gross calorific value or, when necessary, density data are missing or invalid for an oil or gas sample taken according to the procedures in section 2.2.3, 2.2.4.1, 2.2.4.2, 2.2.4.3, 2.2.5, 2.2.6, 2.2.7, 2.3.3.1.2, or 2.3.4 of this appendix, then substitute the maximum potential sulfur content, density, or gross calorific value of that fuel from Table D-6 of this appendix. Except for the annual samples of fuel sulfur content required under sections 2.3.1.4 (e), 2.3.2.4 (e) and 2.3.6 (b)(5) of this appendix, the missing data values in Table D-6 shall be reported whenever the results of a required sample of sulfur content, GCV or density is missing or invalid in the current calendar year, irrespective of which reporting option is selected (i.e., actual value, contract value or highest value from the previous year. For the annual samples of fuel sulfur content required under sections 2.3.1.4 (e), 2.3.2.4 (e) and 2.3.6 (b)(5) of this appendix, if a valid annual sample has not been obtained by the end of a particular calendar year, the appropriate missing data value in Table D-6 shall be reported, beginning with the first unit operating hour in the next calendar year. The substitute data value(s) shall be used until the next valid sample for the missing parameter(s) is obtained. Note that only actual sample results shall be used to determine the "highest value from the previous year" when that reporting option is used; missing data values shall not be used in the determination.

TABLE D-6. -- MISSING DATA SUBSTITUTION PROCEDURES FOR SULFUR, DENSITY, AND GROSS CALORIFIC VALUE DATA

Parameter	Missing data substitution maximum potential value
Oil Sulfur Content	3.5 percent for residual oil, or 1.0 percent for diesel fuel.
Oil Density	8.5 lb/gal for residual oil, or 7.4 lb/gal for diesel fuel.
Oil GCV	19,500 Btu/lb for residual oil, or 20,000 Btu/lb for diesel fuel.
Gas Total Sulfur Content*	1. For pipeline natural gas, where annual sampling is required, substitute 0.002 lb/mmBtu for each hour of the missing data period. 2. For natural gas (or other gaseous fuel that qualifies to use a default SO_2 emission rate under section 2.3.6 of this appendix), where annual sampling is required, substitute 1.5 times the default SO_2 emission rate in use at the time of the missing data period. 3. For any gaseous fuel sampled daily, 1.5 times the highest total sulfur content value from the previous 30 days on which valid samples were obtained. 4. For any gaseous fuel sampled hourly, the highest total sulfur content value from the previous 720 hourly samples.
Gas GCV/Heat Content	110,000 Btu/100 scf for pipeline natural gas, natural gas or landfill gas. 150,000 Btu/100 scf for butane or refinery gas. 210,000 Btu/100 scf for propane or any other gaseous fuel.

* Required no later than July 1, 2003.

App. D § 2.4.2

2.4.2 Missing Data Procedures for Fuel Flow Rate

Whenever data are missing from any primary fuel flowmeter system (as defined in § 72.2 of this chapter) and there is no backup system available to record the fuel flow rate, use the procedures in sections 2.4.2.2 and 2.4.2.3 of this appendix to account for the flow rate of fuel combusted at the unit for each hour during the missing data period. Alternatively, for a fuel flowmeter system used to measure the fuel combusted by a peaking unit, the simplified fuel flow missing data procedure in section 2.4.2.1 of this appendix may be used. Before using the procedures in sections 2.4.2.2 and 2.4.2.3 of this appendix, establish load ranges for the unit using the procedures of section 2 in appendix C to this part, except for units that do not produce electrical output (i.e., megawatts) or thermal output (e.g., klb of steam per hour). The owner or operator of a unit that does not produce electrical or thermal output shall either perform missing data substitution without segregating the fuel flow rate data into bins, or may petition the Administrator under § 75.66 for permission to segregate the data into operational bins. When load ranges are used for fuel flow rate missing data purposes, separate, fuel-specific databases shall be created and maintained. A database shall be kept for each type of fuel combusted in the unit, for the hours in which the fuel is combusted alone in the unit. An additional database shall be kept for each type of fuel, for the hours in which it is co-fired with any other type(s) of fuel(s).

App. D § 2.4.2.1

2.4.2.1 Simplified Fuel Flow Rate Missing Data Procedure for Peaking Units

If no fuel flow rate data are available for a fuel flowmeter system installed on a peaking unit (as defined in § 72.2 of this chapter), then substitute for each hour of missing data using the maximum potential fuel flow rate. The maximum potential fuel flow rate is the lesser of the following: (a) The maximum fuel flow rate the unit is capable of combusting or
(b) The maximum flow rate that the fuel flowmeter can measure (i.e, the upper range value of the flowmeter).

App. D § 2.4.2.2

2.4.2.2 Standard Missing Data Procedures–Single Fuel Hours.

For missing data periods that occur when only one type of fuel is being combusted, provide substitute data for each hour in the missing data period as follows.

2.4.2.2.1 If load-based missing data procedures are used, substitute the arithmetic average of the hourly fuel flow rate(s) measured and recorded by a certified fuel flowmeter system at the corresponding operating unit load range during the previous 720 operating hours in which the unit combusted only that same fuel. If no fuel flow rate data are available at the corresponding load range, use data from the next higher load range, if such data are available. If no quality-assured fuel flow rate data are available at either the corresponding load range or a higher load range, substitute the maximum potential fuel flow rate (as defined in section 2.4.2.1 of this appendix) for each hour of the missing data period. .

2.4.2.2.2 For units that do not produce electrical or thermal output and therefore cannot use load-based missing data procedures, provide substitute data for each hour of the missing data period as follows. Substitute the arithmetic average of the hourly fuel flow rates measured and recorded by a certified fuel flowmeter system during the previous 720 operating hours in which the unit combusted only that same fuel. If no quality-assured fuel flow rate data are available, substitute the maximum potential fuel flow rate (as defined in section 2.4.2.1 of this appendix) for each hour of the missing data period.

App. D § 2.4.2.3

2.4.2.3 Standard Missing Data Procedures---Multiple Fuel Hours.

For missing data periods that occur when two or more fuels different types of fuel are being co-fired, provide substitute fuel flow rate data for each hour of the missing data period as follows.

2.4.2.3.1 If load-based missing data procedures are used, substitute the maximum hourly fuel flow rate measured and recorded by a certified fuel flowmeter system at the corresponding load range during the previous 720 operating hours when the fuel for which the flow rate data are missing was co-fired with any other type of fuel. If no such quality-assured fuel flow rate data are available at the corresponding load range, use data from the next higher load range (if available). If no quality-assured fuel flow rate data are available for co-fired hours, either at the corresponding load range or a higher load range, substitute the maximum potential fuel flow rate (as defined in section 2.4.2.1 of this appendix) for each hour of the missing data period.

2.4.2.3.2 For units that do not produce electrical or thermal output and therefore cannot use load-based missing data procedures, provide substitute fuel flow rate data for each hour of the missing data period as follows. Substitute the maximum hourly fuel flow rate measured and recorded by a certified fuel flowmeter system during the previous 720 operating hours in which the fuel for which the flow rate data are missing was co-fired with any other type of fuel. If no quality-assured fuel flow rate data for co-fired hours are available, substitute the maximum potential fuel flow rate (as defined in section 2.4.2.1 of this appendix) for each hour of the missing data period.

2.4.2.3.3 If, during an hour in which different types of fuel are co-fired, quality-assured fuel flow rate data are missing for two or more of the fuels being combusted, apply the procedures in section 2.4.2.3.1 or 2.4.2.3.2 of this appendix (as applicable) separately for each type of fuel.

2.4.2.3.4 If the missing data substitution required in section 2.4.2.3.1 or 2.4.2.3.2 causes the

reported hourly heat input rate based on the combined fuel usage to exceed the maximum rated hourly heat input of the unit, adjust the substitute fuel flow rate value(s) so that the reported heat input rate equals the unit's maximum rated hourly heat input. Manual entry of the adjusted substitute data values is permitted.

App. D § 2.4.3

2.4.3 In any case where the missing data provisions of this section require substitution of data measured and recorded more than three years (26,280 clock hours) prior to the date and time of the missing data period, use three years (26,280 clock hours) in place of the prescribed lookback period. In addition, for a new or newly-affected unit, until 720 hours of quality-assured fuel flowmeter data are available for the lookback periods described in sections 2.4.2.2 and 2.4.2.3 of this appendix, use all of the available fuel flowmeter data to determine the appropriate substitute data values.

App. D § 3

3. Calculations

Calculate hourly SO_2 mass emission rate from combustion of oil fuel using the procedures in section 3.1 of this appendix. Calculate hourly SO_2 mass emission rate from combustion of gaseous fuel using the procedures in section 3.3 of this appendix. (Note: the SO_2 mass emission rates in sections 3.1 and 3.3 are calculated such that the rate, when multiplied by unit operating time, yields the hourly SO_2 mass emissions for a particular fuel for the unit.) Calculate hourly heat input rate for both oil and gaseous fuels using the procedures in section 3.4 of this appendix. Calculate total SO_2 mass emissions and heat input for each hour, each quarter and the year to date using the procedures under section 3.5 of this appendix. Where an oil flowmeter records volumetric flow rate, use the calculation procedures in section 3.2 of this appendix to calculate the mass flow rate of oil.

App. D § 3.1

3.1 SO_2 Mass Emission Rate Calculation for Oil

3.1.1 Use Equation D-2 to calculate SO_2 mass emission rate per hour (lb/hr):

$$SO2_{rate-oil} = 2.0 \times OIL_{rate} \times \frac{\%S_{oil}}{100.0}$$

(Eq. D-2)
Where:
$SO_{2\ rate\text{-}oil}$ = Hourly mass emission rate of SO_2 emitted from combustion of oil, lb/hr.
OIL_{rate} = Mass rate of oil consumed per hr during combustion, lb/hr.
$\%S_{oil}$ = Percentage of sulfur by weight in the oil.
2.0 = Ratio of lb SO_2/lb S.

3.1.2 Record the SO_2 mass emission rate from oil for each hour that oil is combusted.

App. D § 3.2

3.2 Mass Flow Rate Calculation for Volumetric Oil Flowmeters

App. D § 3.2.1

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.

App. D § 3.2.2

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 (1997)e1 ~~(Reapproved 1990)~~, "Standard Guide for Petroleum Measurement Tables" (incorporated by reference under § 75.6 of this part).

App. D § 3.2.3

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):

$$OIL_{rate} = V_{oil-rate} \times D_{oil}$$

(Eq. D-3)
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.

App. D § 3.3 *3.3 SO_2 Mass Emission Rate Calculation for Gaseous Fuels*

App. D § 3.3.1 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:

$$SO2_{rate-gas} = \left(\frac{2.0}{7000}\right) \times GAS_{rate} \times S_{gas}$$

[Comment: The term "2" in the numerator of Eq. D-4 has been corrected to read, "2.0"]

(Eq. D-4)
Where:
$SO_{2\ rate-gas}$ = 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.

App. D § 3.3.2 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:

$$SO2_{rate} = ER \times HI_{rate}$$

(Eq. D-5)
Where:
$SO_{2\ rate}$ = 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} = Hourly heat input rate of a gaseous fuel, calculated using procedures in section 3.4.1 of this appendix, in mmBtu/hr.

App. D § 3.3.3 3.3.3 Record the SO_2 mass emission rate for each hour when the unit combusts a gaseous fuel.

App. D § 3.4 *3.4 Calculation of Heat Input Rate*

App. D § 3.4.1 3.4.1 Heat Input Rate for Gaseous Fuels

App. D § 3.4.1(a) (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.

App. D § 3.4.1(b) (b) Then, use Equation D-6 to calculate heat input rate from gaseous fuels for each hour.

$$HI_{rate-gas} = \frac{GAS_{rate} \times GCV_{gas}}{10^6}$$

(Eq. D-6)
Where:
$HI_{rate-gas}$ = Hourly heat input rate from combustion of the gaseous fuel, mmBtu/hr.
GAS_{rate} = Average volumetric flow rate of fuel, for the portion of the hour in which the unit operated, 100 scf/hr.
GCV_{gas} = Gross calorific value of gaseous fuel, Btu/100 scf.
10^6 = Conversion of Btu to mmBtu.

App. D § 3.4.1(c)

(c) Note that when fuel flow is measured on an hourly totalized basis (e.g. a fuel flowmeter reports totalized fuel flow for each hour), before Equation D-6 can be used, the total hourly fuel usage must be converted from units of 100 scf to units of 100 scf/hr using Equation D-7:

$$GAS_{rate} = \frac{GAS_{unit}}{t}$$

(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).

App. D § 3.4.2

3.4.2 Heat Input Rate from the Combustion of Oil

App. D § 3.4.2(a)

(a) Determine total hourly oil flow or average hourly oil flow rate with a fuel flowmeter, in accordance with the requirements of section 2.1 of this appendix. Determine oil GCV according to the requirements of section 2.2 of this appendix.
Then, use Equation D-8 to calculate hourly heat input rate from oil for each hour:

$$HI_{rate-oil} = OIL_{rate} \frac{GCV_{oil}}{10^6}$$

(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, or Btu/kg.
10^6 = Conversion of Btu to mmBtu.

App. D § 3.4.2 (b)

(b) Note that when fuel flow is measured on an hourly totalized basis (e.g., a fuel flowmeter reports totalized fuel flow for each hour), before equation D-8 can be used, the total hourly fuel usage must be converted from units of lb to units of lb/hr, using equation D-9:

$$OIL_{rate} = \frac{OIL_{unit}}{t}$$

(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).

App. D § 3.4.2 (c)

(c) For affected units that are not subject to an Acid Rain emissions limitation, but are regulated under a State or federal NO_x mass emissions reduction program that adopts the requirements of subpart H of this part, the following alternative method may be used to determine the heat input rate from oil combustion, when the oil flowmeter measures the flow rate of oil volumetrically. In lieu of measuring the oil density and converting the volumetric oil flow rate to a mass flow rate, Equation D-8 may be applied on a volumetric basis. If this option is selected, express the terms OIL_{rate} and GCV_{oil} in Equation D-8 in units of volume rather than mass. For example, the units of OIL_{rate} may be gal/hr and the units of GCV_{oil} may be Btu/gal.

App. D § 3.4.3

3.4.3 Apportioning Heat Input Rate to Multiple Units

App. D § 3.4.3(a)

(a) Use the procedure in this section to apportion hourly heat input rate to two or more units using a single fuel flowmeter which supplies fuel to the units. The designated representative may also petition the Administrator under § 75.66 to use this apportionment procedure to calculate SO_2 and CO_2 mass emissions.

App. D § 3.4.3(b)

(b) Determine total hourly fuel flow or flow rate through the fuel flowmeter supplying gas or oil fuel to the units. Convert fuel flow rates to units of 100 scf for gaseous fuels or to lb for oil, using the procedures of this appendix. Apportion the fuel to each unit separately based on hourly output of the unit in MW_e or 1000 lb of steam/hr (klb/hr) using Equation F-21a or F-21b in appendix F to this part, as applicable.

App. D § 3.4.3(c)

(c) Use the total apportioned fuel flow calculated from Equation F-21a or F-21b to calculate the hourly unit heat input rate, using Equations D-6 and D-7 (for gas) or Equations D-8 and D-9 (for oil).

App. D § 3.5

3.5 *Conversion of Hourly Rates to Hourly, Quarterly, and Year-to-Date Totals*

App. D § 3.5.1

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:

$$M_{SO2-hr} = \sum_{all-fuels} SO2_{rate-i}\, t_i$$

(Eq. D-12)
Where:
M_{SO2-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).

App. D § 3.5.2

3.5.2 Quarterly Total SO_2 Mass Emissions

Sum the hourly SO_2 mass emissions in lb as determined from Equation D-12 for all hours in a quarter using Equation D-13:

$$M_{SO2-qtr} = \frac{1}{2000} \sum_{all-hours-in-qtr} M_{SO2-hr}$$

(Eq. D-13)
Where:
$M_{SO2-qtr}$ = Total mass of SO_2 emissions from all fuels combusted during the quarter, tons.
M_{SO2-hr} = Hourly SO_2 mass emissions determined using Equation D-12, lb.
2000 = Conversion factor from lb to tons.

App. D § 3.5.3

3.5.3 Year to Date SO_2 Mass Emissions

Calculate and record SO_2 mass emissions in the year to date using Equation D-14:

$$M_{SO2-YTD} = \sum_{q=1}^{current-quarter} M_{SO2-qtr}$$

(Eq. D-14)
Where:
$M_{SO2-YTD}$ = Total SO_2 mass emissions for the year to date, tons.
$M_{SO2-qtr}$ = Total SO_2 mass emissions for the quarter, tons.

App. D § 3.5.4

3.5.4 Hourly Total Heat Input Rate and Heat Input from the Combustion of all Fuels

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

$$HI_{hr} = \sum_{all-fuels} HI_{rate-i} t_i$$

(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 an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

3.5.4.2 For reporting purposes, determine the heat input rate to each unit, in mmBtu/hr, for each hour from the combustion of all fuels using Equation D-15a:

$$HI_{rate-hr} = \frac{\sum_{all-fuels} HI_{rate-i}\, t_i}{t_u}$$

(Eq. D-15a)
Where:
$HI_{rate-hr}$ = Total heat input rate from all fuels combusted during the hour, mmBtu/hr.
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 an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).
t_u = Unit operating time

App. D § 3.5.5 3.5.5 Quarterly Heat Input

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

$$HI_{qtr} = \sum_{all-hours-in-qtr} HI_{hr}$$

(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.

App. D § 3.5.6 3.5.6 Year-to-Date Heat Input

Calculate and record the total heat input in the year to date using Equation D-17.

$$HI_{YTD} = \sum_{q=1}^{current-quarter} HI_{qtr}$$

(Eq. D-17)
HI_{YTD} = Total heat input for the year to date, mmBtu.
HI_{qtr} = Total heat input for the quarter, mmBtu.

App. D § 3.6 3.6 *Records and Reports*

Calculate and record quarterly and cumulative SO_2 mass emissions and heat input for each calendar quarter using the procedures and equations of section 3.5 of this appendix. Calculate and record SO_2 emissions and heat input data in a standard electronic format specified by the Administrator.

Appendix E to Part 75 -- Optional NO_x Emissions Estimation Protocol for Gas-Fired Peaking Units and Oil-Fired Peaking Units

App. E § 1 **1. Applicability**

App. E § 1.1 *1.1 Unit Operation Requirements*

This NO_x emissions estimation procedure may be used in lieu of a continuous NO_x emission monitoring system (lb/mmBtu) for determining the average NO_x emission rate and hourly NO_x rate from gas-fired peaking units and oil-fired peaking units as defined in § 72.2 of this chapter. If a unit's operations exceed the levels required to be a peaking unit, the owner or operator shall install and certify a NO_x-diluent continuous emission monitoring system no later than December 31 of the following calendar year. If the required CEMS has not been installed and certified by that date, the owner or operator shall report the maximum potential NO_x emission rate (MER) (as defined in § 72.2 of this chapter) for each unit operating hour, starting with the first unit operating hour after the deadline and continuing until the CEMS has been provisionally certified. The provisions of § 75.12 apply to excepted monitoring systems under this appendix.

App. E § 1.2 *1.2 Certification*

1.2.1 Pursuant to the procedures in § 75.20, complete all testing requirements to certify use of this protocol in lieu of a NO_x continuous emission monitoring system no later than the applicable deadline specified in § 75.4. Apply to the Administrator for certification to use this method no later than 45 days after the completion of all certification testing. Whenever the monitoring method is to be changed, reapply to the Administrator for certification of the new monitoring method.

1.2.2 [Reserved]

App. E § 2 **2. Procedure**

App. E § 2.1 *2.1 Initial Performance Testing*

Use the following procedures for: measuring NO_x emission rates at heat input rate levels corresponding to different load levels; measuring heat input rate; and plotting the correlation between heat input rate and NO_x emission rate, in order to determine the emission rate of the unit(s). The requirements in section 6.1.2 of appendix A to this part shall be met by any Air Emissions Testing Body (AETB) performing O_2 and NO_x concentration measurements under this appendix, either for units using the excepted methodology in this appendix or for units using the low mass emissions excepted methodology in § 75.19.

App. E § 2.1.1 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.

App. E § 2.1.2 2.1.2 NO_x and O_2 Concentration Measurements

Use the following procedures to measure NO_x and O_2 concentration in order to determine NO_x emission rate.

App. E § 2.1.2.1 2.1.2.1 For boilers, select an excess O_2 level for each fuel (and, optionally, for each combination of fuels) to be combusted that is representative for each of the four or more load levels. If a boiler operates using a single, consistent combination of fuels only, the testing may be performed using the combination rather than each fuel. If a fuel is combusted only for the purpose of testing ignition of the burners for a period of five minutes or less per ignition test or for start-up, then the boiler NO_x emission rate does not need to be tested separately for that fuel. Operate the boiler at a normal or conservatively high excess oxygen level in conjunction with these tests. Measure the NO_x and O_2 at each load point for each fuel or consistent fuel combination (and, optionally, for each combination of fuels) to be combusted. Measure the NO_x and O_2 concentrations according to method 7E and 3A in appendix A of part 60 of this chapter. Select sampling points as specified in ~~section 5.1~~ section 8.3.1, 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.

App. E § 2.1.2.2 2.1.2.2 For stationary gas turbines, select sampling points and measure the NO_x and O_2 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_x and O_2 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.

App. E § 2.1.2.3

2.1.2.3 Allow the unit to stabilize for a minimum of 15 minutes (or longer if needed for the NO_x and O_2 readings to stabilize) prior to commencing NO_x, O_2, and heat input measurements. Determine the 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.

App. E § 2.1.3

2.1.3 Heat Input

Measure the total heat input (mmBtu) and heat input rate during testing (mmBtu/hr) as follows:

App. E § 2.1.3.1

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.

App. E § 2.1.3.2

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.

App. E § 2.1.4

2.1.4 Emergency Fuel

The designated representative of a unit that is restricted by its federal, State or local permit to combusting a particular fuel only during emergencies where the primary fuel is not available may claim an exemption from the requirements of this appendix for testing the NO_x emission rate during combustion of the emergency fuel. To claim this exemption, the designated representative shall include in the monitoring plan for the unit documentation that the permit restricts use of the fuel to emergencies only. When emergency fuel is combusted, report the maximum potential NO_x emission rate for the emergency fuel, in accordance with section 2.5.2.3 of this appendix. The designated representative shall also provide notice under § 75.61(a)(6) for each period when the emergency fuel is combusted.

2.1.5 Tabulation of Results

App. E § 2.1.5

Tabulate the results of each baseline correlation test for each fuel or, as applicable, combination of fuels, listing: time of test, duration, operating loads, heat input rate (mmBtu/hr), F-factors, excess oxygen levels, and NO_x concentrations (ppm) on a dry basis (at actual excess oxygen level). Convert the NO_x concentrations (ppm) to NO_x emission rates (to the nearest 0.001 lb/mm/Btu) according to Equation F-5 of appendix F of this part or 19-3 in method 19 of appendix A of part 60 of this chapter, as appropriate. Calculate the NO_x emission rate in lb/mmBtu for each sampling point and determine the arithmetic average NO_x emission rate of each test run. Calculate the arithmetic average of the boiler excess oxygen readings for each test run. Record the arithmetic average of the three test runs as the NO_x emission rate and the boiler excess oxygen level for the heat input/load condition.

App. E § 2.1.6

2.1.6 Plotting of Results

Plot the tabulated results as an x-y graph for each fuel and (as applicable) combination of fuels combusted according to the following procedures.

2.1.6.1 Plot the heat input rate (mmBtu/hr) as the independent (or x) variable and the NO_x emission rates (lb/mmBtu) as the dependent (or y) variable for each load point. Construct the graph by drawing straight line segments between each load point. Draw a horizontal line to the y-axis from the minimum heat input (load) point.

2.1.6.2 Units that co-fire gas and oil may be tested while firing gas only and oil only instead of testing with each combination of fuels. In this case, construct a graph for each fuel.

App. E § 2.2

2.2 Periodic NO_x Emission Rate Testing

Retest the NO_x emission rate of the gas-fired peaking unit or the oil-fired peaking unit while combusting each type of fuel (or fuel mixture) for which a NO_x emission rate versus heat input rate correlation curve was derived, at least once every 20 calendar quarters. If a required retest is not completed by the end of the 20th calendar quarter following the quarter of the last test, use the missing data substitution procedures in section 2.5 of this appendix, beginning with the first unit operating hour after the end of the 20th calendar quarter. Continue using the missing data procedures until the required retest has been passed. Note that missing data substitution is fuel-specific (i.e., the use of substitute data is required only when combusting a fuel (or fuel mixture) for which the retesting deadline has not been met). Each time that a new fuel-specific correlation curve is derived from retesting, the new curve shall be used to report NO_x emission rate, beginning with the first operating hour in which the fuel is combusted, following the completion of the retest. Notwithstanding this requirement, for non-Acid Rain Program units that report NO_x mass emissions and heat input data only during the ozone season under § 75.74 (c), if the NO_x emission rate testing is performed outside the ozone season, the new correlation curve may be used beginning with the first unit operating hour in the ozone season immediately following the testing.

App. E § 2.3

2.3 Other Quality Assurance/Quality Control-Related NO_x Emission Rate Testing

When the operating levels of certain parameters exceed the limits specified below, or where the Administrator issues a notice requesting retesting because the NO_x emission rate data availability for when the unit operates within all quality assurance/quality control parameters in this section since the last test is less than 90.0 percent, as calculated by the Administrator, complete retesting of the NO_x emission rate by the earlier of: (1) 30 unit operating days (as defined in § 72.2 of this chapter) or (2) 180 calendar days after exceeding the limits or after the date of issuance of a notice from the Administrator to re-verify the unit's NO_x emission rate. Submit test results in accordance with § 75.60 within 45 days of completing the retesting.

App. E § 2.3.1

2.3.1 For a stationary gas turbine, select at least four operating parameters indicative of the turbine's NO_x formation characteristics, and define in the QA plan for the unit the acceptable ranges for these parameters at each tested load-heat input point. The acceptable parametric ranges should be based upon the turbine manufacturer's recommendations. Alternatively, the owner or operator may use sound engineering judgment and operating experience with the unit to establish the acceptable parametric ranges, provided that the rationale for selecting these ranges is included as part of the quality-assurance plan for the unit. If the gas turbine uses water or steam injection for NO_x control, the water/fuel or steam/fuel ratio shall be one of these parameters. During the NO_x-heat input correlation tests, record the average value of each parameter for each load-heat input to ensure that the parameters are within the acceptable range. Redetermine the NO_x emission rate-heat input correlation for each fuel and (optional) combination of fuels after continuously exceeding the acceptable range of any of these parameters for one or more successive operating periods totaling more than 16 unit operating hours.

App. E § 2.3.2

2.3.2 For a diesel or dual-fuel reciprocating engine, select at least four operating parameters

indicative of the engine's NO_x formation characteristics, and define in the QA plan for the unit the acceptable ranges for these parameters at each tested load-heat input point. The acceptable parametric ranges should be based upon the engine manufacturer's recommendations. Alternatively, the owner or operator may use sound engineering judgment and operating experience with the unit to establish the acceptable parametric ranges, provided that the rationale for selecting these ranges is included as part of the quality-assurance plan for the unit. Any operating parameter critical for NO_x control shall be included. During the NO_x heat-input correlation tests, record the average value of each parameter for each load-heat input to ensure that the parameters are within the acceptable range. Redetermine the NO_x emission rate-heat input correlation for each fuel and (optional) combination or fuels after continuously exceeding the acceptable range of any of these parameters for one or more successive operating periods totaling more than 16 unit operating hours.

App. E § 2.3.3

2.3.3 For boilers using the procedures in this appendix, the NO_x emission rate heat input correlation for each fuel and (optional) combination of fuels shall be redetermined if the excess oxygen level at any heat input rate (or unit operating load) continuously exceeds by more than 2 percentage points O_2 from the boiler excess oxygen level recorded at the same operating heat input rate during the previous NO_x emission rate test for one or more successive operating periods totaling more than 16 unit operating hours.

App. E § 2.4

2.4 Procedures for Determining Hourly NO_x Emission Rate

App. E § 2.4.1

2.4.1 Record the time (hr. and min.), load (MWge or steam load in 1000 lb/hr, or mmBtu/hr thermal output), fuel flow rate and heat input rate (using the procedures in section 2.1.3 of this appendix) for each hour during which the unit combusts fuel. Calculate the total hourly heat input using equation E-1 of this appendix. Record the heat input rate for each fuel to the nearest 0.1 mmBtu/hr. During partial unit operating hours or during hours where more than one fuel is combusted, heat input must be represented as an hourly rate in mmBtu/hr, as if the fuel were combusted for the entire hour at that rate (and not as the actual, total heat input during that partial hour or hour) in order to ensure proper correlation with the NO_x emission rate graph.

App. E § 2.4.2

2.4.2 Use the graph of the baseline correlation results (appropriate for the fuel or fuel combination) to determine the NO_x emissions rate (lb/mmBtu) corresponding to the heat input rate (mmBtu/hr). Input this correlation into the data acquisition and handling system for the unit. Linearly interpolate to 0.1 mmBtu/hr heat input rate and 0.001 lb/mmBtu NO_x. For each type of fuel, calculate NO_x emission rate using the baseline correlation results from the most recent test with that fuel, beginning with the date and hour of the completion of the most recent test.

App. E § 2.4.3

2.4.3 To determine the NO_x emission rate for a unit co-firing fuels that has not been tested for that combination of fuels, interpolate between the NO_x emission rate for each fuel as follows. Determine the heat input rate for the hour (in mmBtu/hr) for each fuel and select the corresponding NO_x emission rate for each fuel on the appropriate graph. (When a fuel is combusted for a partial hour, determine the fuel usage time for each fuel and determine the heat input rate from each fuel as if that fuel were combusted at that rate for the entire hour in order to select the corresponding NO_x emission rate.) Calculate the total heat input to the unit in mmBtu for the hour from all fuel combusted using Equation E-1. Calculate a Btu-weighted average of the emission rates for all fuels using Equation E- 2 of this appendix. For each type of fuel, calculate NO_x emission rate using the baseline correlation results from the most recent test with that fuel, beginning with the date and hour of the completion of the most recent test.

App. E § 2.4.4

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.

App. E § 2.5

2.5 Missing Data Procedures

Provide substitute data for each unit electing to use this alternative procedure whenever a valid quality-assured hour of NO_x emission rate data has not been obtained according to the

procedures and specifications of this appendix. For the purpose of providing substitute data, calculate the maximum potential NO_x emission rate (as defined in § 72.2 of this chapter) for each type of fuel combusted in the unit.

App. E § 2.5.1

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.

App. E § 2.5.2

2.5.2 Substitute missing NO_x emission rate data using the highest NO_x emission rate tabulated during the most recent set of baseline correlation tests for the same fuel or, if applicable, combination of fuels, except as provided in sections ~~paragraphs~~ 2.5.2.1, 2.5.2.2, ~~and~~ 2.5.2.3, and 2.5.2.4 of this ~~appendix~~ section. ~~Manual substitution of the missing data values required under sections 2.5.2.1 and 2.5.2.2 of this appendix is permitted through March 31, 2003, after which these substitutions must be performed automatically by the data acquisition and handling system. Manual substitution of the missing data values required under section 2.5.2.3 of this appendix is permitted at all times.~~

2.5.2.1 If the measured heat input rate during any unit operating hour is higher than the highest heat input rate from the baseline correlation tests, the NO_x emission rate for the hour is considered to be missing. Provide substitute data for each such hour, according to section 2.5.2.1.1 or 2.5.2.1.2 of this appendix, as applicable. Either:

2.5.2.1.1 Substitute the higher of: the NO_x emission rate obtained by linear extrapolation of the correlation curve, or the maximum potential NO_x emission rate (MER) (as defined in § 72.2 of this chapter), specific to the type of fuel being combusted. (For fuel mixtures, substitute the highest NO_x MER value for any fuel in the mixture.) For units with NO_x emission controls, the extrapolated NO_x emission rate may only be used if the controls are documented (e.g., by parametric data) to be operating properly during the missing data period (see section 2.5.2.2 of this appendix); or

2.5.2.1.2 Substitute 1.25 times the highest NO_x emission rate from the baseline correlation tests for the fuel (or fuel mixture) being combusted in the unit, not to exceed the MER for that fuel (or mixture). For units with NO_x emission controls, the option to report 1.25 times the highest emission rate from the correlation curve may only be used if the controls are documented (e.g., by parametric data) to be operating properly during the missing data period (see section 2.5.2.2 of this appendix).

2.5.2.2 For a unit with add-on NO_x emission controls (e.g., steam or water injection, selective catalytic reduction), if, for any unit operating hour, the emission controls are either not in operation or if appropriate parametric data are unavailable to ensure proper operation of the controls, the NO_x emission rate for the hour is considered to be missing. Substitute the fuel-specific MER (as defined in § 72.2 of this chapter) for each such hour.

2.5.2.3 When emergency fuel (as defined in § 72.2) is combusted in the unit, report the fuel-specific NO_x MER for each hour that the fuel is combusted, unless a NO_x correlation curve has been derived for the fuel.

2.5.2.4 Whenever 20 full calendar quarters have elapsed following the quarter of the last baseline correlation test for a particular type of fuel (or fuel mixture), without a subsequent baseline correlation test being done for that type of fuel (or fuel mixture), substitute the fuel-specific NO_x MER (as defined in § 72.2 of this chapter) for each hour in which that fuel (or mixture) is combusted until a new baseline correlation test for that fuel (or mixture) has been successfully completed. For fuel mixtures, report the highest of the individual MER values for the components of the mixture.

App. E § 2.5.3

2.5.3 Maintain a record indicating which data are substitute data and the reasons for the failure to provide a valid quality-assured hour of NO_x emission rate data according to the procedures and specifications of this appendix.

App. E § 2.5.4 2.5.4 Substitute missing data from a fuel flowmeter using the procedures in section 2.4.2 of appendix D to this part.

App. E § 2.5.5 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.

App. E § 3 3. Calculations

App. E § 3.1 *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:

$$H_T = HI_{fuel\,1}\,t_1 + HI_{fuel\,2}\,t_2 + HI_{fuel\,3}\,t_3 + \ldots + HI_{lastfuel}\,t_{last}$$

(Eq. E-1)

Where:

H_T = Total heat input of fuel flow or a combination of fuel flows to a unit, mmBtu.

$HI_{fuel\ 1,2,3,...last}$ =Heat input rate from each fuel, in mmBtu/hr as determined using Equation F-19 or F-20 in section 5.5 of appendix F to this part, mmBtu/hr.

$t_{1,2,3....last}$ = Fuel usage time for each fuel (rounded up to the nearest fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

App. E § 3.2 *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.

App. E § 3.3 *3.3 NO_x Emission Rate*

App. E § 3.3.1 3.3.1 Conversion from Concentration to Emission Rate

Convert the NO_x concentrations (ppm) and O_2 concentrations to NO_x emission rates (to the nearest 0.01 lb/mmBtu for tests performed prior to April 1, 2000, or to the nearest 0.001 lb/mmBtu for tests performed on and after April 1, 2000), according to the appropriate one of the following equations: F-5 in appendix F to this part for dry basis concentration measurements or 19-3 in Method 19 of appendix A to part 60 of this chapter for wet basis concentration measurements.

App. E § 3.3.2 3.3.2 Quarterly Average NO_x Emission Rate

Report the quarterly average emission rate (lb/mmBtu) as required in subpart G of this part. Calculate the quarterly average NO_x emission rate according to equation F-9 in appendix F of this part.

App. E § 3.3.3 3.3.3 Annual Average NO_x Emission Rate

Report the average emission rate (lb/mmBtu) for the calendar year as required in subpart G of this part. Calculate the average NO_x emission rate according to equation F-10 in appendix F of this part.

App. E § 3.3.4 3.3.4 Average NO_x Emission Rate During Co-firing of Fuels

$$E_h = \frac{\sum_{f=1}^{all\ fuels} (E_f \times HI_f\, t_f)}{H_T}$$

(Eq. E-2)
Where:
E_h = NO_x emission rate for the unit for the hour, lb/mmBtu.
E_f = NO_x emission rate for the unit for a given fuel at heat input rate HI_f, lb/mmBtu.
HI_f = Heat input rate for the hour for a given fuel, during the fuel usage time, as determined using Equation F-19 or F-20 in section 5.5 of appendix F to this part, mmBtu/hr.
H_T = Total heat input for all fuels for the hour from Equation E-1.
t_f = Fuel usage time for each fuel (rounded 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.

App. E § 4

4. Quality Assurance/Quality Control Plan

Include a section on the NO_x emission rate determination as part of the monitoring quality assurance/quality control plan required under § 75.21 and appendix B of this part for each gas-fired peaking unit and each oil-fired peaking unit. In this section present information including, but not limited to, the following: (1) a copy of all data and results from the initial NO_x emission rate testing, including the values of quality assurance parameters specified in Section 2.3 of this appendix; (2) a copy of all data and results from the most recent NO_x emission rate load correlation testing; (3) a copy of the recommended range of quality assurance- and quality control-related operating parameters.

App. E § 4.1

4.1 Submit a copy of the recommended range of operating parameter values, and the range of operating parameter values recorded during the previous NO_x emission rate test that determined the unit's NO_x emission rate, along with the unit's revised monitoring plan submitted with the certification application.

App. E § 4.2

4.2 Keep records of these operating parameters for each hour of operation in order to demonstrate that a unit is remaining within the recommended operating range.

Appendix F to Part 75 -- Conversion Procedures

App. F § 1

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.

App. F § 2

2. Procedures for SO_2 Emissions

Use the following procedures to compute hourly SO_2 mass emission rate (in lb/hr) and quarterly and annual SO_2 total mass emissions (in tons). ~~Use the procedures in Method 19 in appendix A to part 60 of this chapter to compute hourly SO_2 emission rates (in lb/mmBtu) for qualifying Phase I technologies. When computing hourly SO_2 emission rate in lb/mmBtu, a minimum concentration of 5.0 percent CO_2 and a maximum concentration of 14.0 percent O_2 may be substituted for measured diluent gas concentration values at boilers during hours when the hourly average concentration of CO_2 is less than 5.0 percent CO_2 or the hourly average concentration of O_2 is greater than 14.0 percent O_2.~~

App. F § 2.1

2.1 When measurements of SO_2 concentration and flow rate are on a wet basis, use the following equation to compute hourly SO_2 mass emission rate (in lb/hr):

$$E_h = K\, C_h\, Q_h$$

(Eq. F-1)
Where:
E_h = Hourly SO_2 mass emission rate during unit operation, lb/hr.
K = 1.660×10^{-7} for SO_2, (lb/scf)/ppm.
C_h = Hourly average SO_2 concentration during unit operation, stack moisture basis, ppm.
Q_h = Hourly average volumetric flow rate during unit operation, stack moisture basis, scfh.

App. F § 2.2

2.2 When measurements by the SO_2 pollutant concentration monitor are on a dry basis and the flow rate monitor measurements are on a wet basis, use the following equation to compute hourly SO_2 mass emission rate (in lb/hr):

$$E_h = K\, C_{hp}\, Q_{hs} \frac{(100 - \%\, H_2O)}{100}$$

(Eq. F-2)
where:
E_h = Hourly SO_2 mass emission rate during unit operation, lb/hr.
K = 1.660×10^{-7} for SO_2, (lb/scf)/ppm.
C_{hp} = Hourly average SO_2 concentration during unit operation, ppm (dry).
Q_{hs} = Hourly average volumetric flow rate during unit operation, scfh as measured (wet).
$\%H_2O$ = Hourly average stack moisture content during unit operation, percent by volume.

App. F § 2.3

2.3 Use the following equations to calculate total SO_2 mass emissions for each calendar quarter (Equation F-3) and for each calendar year (Equation F-4), in tons:

$$E_q = \frac{\sum_{h=1}^{n} E_h t_h}{2000}$$

(Eq. F-3)

Where:
E_q = Quarterly total SO_2 mass emissions, tons.
E_h = Hourly SO_2 mass emission rate, lb/hr.
t_h = Unit operating time, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).
n = Number of hourly SO_2 emissions values during calendar quarter.
2000 = Conversion of 2000 lb per ton.

$$E_a = \sum_{q=1}^{4} E_q$$

(Eq. F-4)
Where:
E_a = Annual total SO_2 mass emissions, tons.
E_q = Quarterly SO_2 mass emissions, tons.
q = Quarters for which E_q are available during calendar year.

App. F § 2.4

2.4 Round all SO_2 mass emission rates and totals to the nearest tenth.

App. F § 3 **3. Procedures for NO_x Emission Rate**

Use the following procedures to convert continuous emission monitoring system measurements of NO_x concentration (ppm) and diluent concentration (percentage) into NO_x emission rates (in lb/mmBtu). Perform measurements of NO_x and diluent (O_2 or CO_2) concentrations on the same moisture (wet or dry) basis.

App. F § 3.1 *3.1* When the NO_x continuous emission monitoring system uses O_2 as the diluent, and measurements are performed on a dry basis, use the following conversion procedure:

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

(Eq. F-5)
where,
K, E, C_h, F, and $\%O_2$ are defined in section 3.3 of this appendix.

When measurements are performed on a wet basis, use the equations in Method 19 in appendix A-7 ~~of~~ to part 60 of this chapter.

App. F § 3.2 *3.2* When the NO_x continuous emission monitoring system uses CO_2 as the diluent, use the following conversion procedure:

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

(Eq. F-6)
Where:
K, E, Ch, Fc, and $\%CO_2$ are defined in section 3.3 of this appendix.

When CO_2 and NO_x measurements are performed on a different moisture basis, use the equations in Method 19 in appendix A-7 ~~of~~to part 60 of this chapter.

App. F § 3.3 *3.3* Use the definitions listed below to derive values for the parameters in equations F-5 and F-6 of this appendix, or (if applicable) in the equations in Method 19 in appendix A-7 to part 60 of this chapter.

App. F § 3.3.1 3.3.1 K = 1.194×10^{-7} (lb/dscf)/ppm NO_x.

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

App. F § 3.3.3 3.3.3 C_h = Hourly average pollutant concentration during unit operation, ppm.

App. F § 3.3.4 3.3.4 $\%O_2$, $\%CO_2$ = Oxygen or carbon dioxide volume during unit operation (expressed as percent O_2 or CO_2). ~~A minimum concentration of 5.0 percent CO_2 and a maximum concentration of 14.0 percent O_2 may be substituted for measured diluent gas concentration values at boilers during hours when the hourly average concentration of CO_2 is < 5.0 percent CO_2 or the hourly average concentration of O_2 is > 14.0 percent O_2. A minimum concentration of 1.0 percent CO_2 and a maximum concentration of 19.0 percent O_2 may be substituted for measured diluent gas concentration values at stationary gas turbines during hours when the hourly average concentration of CO_2 is < 1.0 percent CO_2 or the hourly average concentration of O_2 is > 19.0 percent O_2.~~

App. F § 3.3.4.1 3.3.4.1 For boilers, a minimum concentration of 5.0 percent CO_2 or a maximum concentration of 14.0 percent O_2 may be substituted for the measured diluent gas concentration value for any

operating hour in which the hourly average CO_2 concentration is < 5.0 percent CO_2 or the hourly average O_2 concentration is > 14.0 percent O_2. For stationary gas turbines, a minimum concentration of 1.0 percent CO_2 or a maximum concentration of 19.0 percent O_2 may be substituted for measured diluent gas concentration values for any operating hour in which the hourly average CO_2 concentration is < 1.0 percent CO_2 or the hourly average O_2 concentration is > 19.0 percent O_2.

App. F § 3.3.4.2

3.3.4.2 If NO_x emission rate is calculated using either Equation 19-3 or 19-5 in Method 19 in appendix A-7 to part 60 of this chapter, a variant of the equation shall be used whenever the diluent cap is applied. The modified equations shall be designated as Equations 19-3D and 19-5D, respectively. Equation 19-3D is structurally the same as Equation 19-3, except that the term "$\%O_{2w}$" in the denominator is replaced with the term "$\%O_{2dc}$ x [(100 - % H_2O)/100]", where $\%O_{2dc}$ is the diluent cap value. The numerator of Equation 19-5D is the same as Equation 19-5; however, the denominator of Equation 19-5D is simply "20.9 - $\%O_{2dc}$", where $\%O_{2dc}$ is the diluent cap value.

App. F § 3.3.5

3.3.5 F, F_c = a factor representing a ratio of the volume of dry flue gases generated to the caloric value of the fuel combusted (F), and a factor representing a ratio of the volume of CO_2 generated to the calorific value of the fuel combusted (F_c), respectively. Table 1 lists the values of F and F_c for different fuels.

TABLE 1.—F- AND F_C- FACTORS[1]

Fuel	F-factor (dscf/mmBtu)	F_C-factor (scf CO_2/mmBtu)
Coal (as defined by ASTM D388-~~92~~99e1):		
Anthracite	10,100	1,970
Bituminous ~~and subbituminous~~	9,780	1,800
Subbituminous	9,819	1,840
Lignite	9,860	1,910
Petroleum Coke	9,832	1,853
Tire Derived Fuel	10,261	1,803
Oil	9,190	1,420
Gas:		
Natural gas	8,710	1,040
Propane	8,710	1,190
Butane	8,710	1,250
Wood:		
Bark	9,600	1,920
Wood residue	9,240	1,830

[1] Determined at standard conditions: 20 °C (68 °F) and 29.92 inches of mercury.

App. F § 3.3.6

3.3.6 Equations F-7a and F-7b may be used in lieu of the F or F_c factors specified in Section 3.3.5 of this appendix to calculate ~~an F factor (dscf/mmBtu) on a dry basis or an F_c factor (scf CO_2/mmBtu) on either a dry or wet basis.~~ a site-specific dry-basis F factor (dscf/mmBtu) or a site-specific F_c factor (scf CO_2/mmBtu), on either a dry or wet basis. At a minimum, the site-specific F or F_c factor must be based on 9 samples of the fuel. Fuel samples taken during each run of a RATA are acceptable for this purpose. The site-specific F or F_c factor must be re-determined at least annually, and the value from the most recent determination must be used in the emission calculations. Alternatively, the previous F or F_c value may continue to be used if it is higher than the value obtained in the most recent determination. The owner or operator shall keep records of all site-specific F or F_c determinations, active for at least 3 years. (Calculate all F- and F_c factors at standard conditions of 20 °C (68 °F) and 29.92 inches of mercury).

~~(Calculate all F- and F_c factors at standard conditions of 20 °C (68 °F) and 29.92 inches of mercury.)~~

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

(Eq. F-7a)

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

(Eq. F-7b)

App. F § 3.3.6.1

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 (1997)e1, "Standard Practice for Ultimate Analysis of Coal and Coke" (solid fuels), ASTM D5291-01 ~~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 D1945-96 (2001) ~~D1945-91~~, "Standard Test Method for Analysis of Natural Gas by Gas Chromatography" or ASTM D1946-90 (2000), "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.)

App. F § 3.3.6.2

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,"~~ ASTM D5865-01ae1 "Standard Test Method for Gross Calorific Value of Coal and Coke," ~~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 D240-00 ~~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)"~~ ASTM D4809-00, "Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method) for oil; and ASTM D3588-98 ~~D3588-91~~ "Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density (Specific Gravity) of Gaseous Fuels," ASTM D4891-89 (2001) "Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion," GPA Standard 2172-1996 ~~86~~ "Calculation of Gross Heating Value, Relative Density and Compressibility Factor for Natural Gas Mixtures from Compositional Analysis," GPA Standard 2261-1999 ~~90~~ "Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography," or ASTM D1826-94 (1998) ~~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).

App. F § 3.3.6.3

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_c value is subject to the Administrator's approval.

App. F § 3.3.6.4

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

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

(Eq. F-8)

where,

X_i = Fraction of total heat input derived from each type of fuel (e.g., natural gas, bituminous coal, wood). Each X_i value shall be determined from the best available information on the quantity of fuel combusted and the GCV value, over a specified time period. The owner or operator shall explain the method used to calculate X_i in the hardcopy portion of the monitoring plan for the unit. The X_i values may be determined and updated either hourly, daily, weekly, or monthly. In all cases, the prorated F-factor used in the emission calculations shall be determined using the X_i values from the most recent update.

F_i or $(F_c)_i$ = Applicable F or F_c factor for each fuel type determined in accordance with Section 3.3.5 of this appendix.

n = Number of fuels being combusted in combination.

App. F § 3.4

3.4 Use the following equations to calculate the average NO_x emission rate for each calendar quarter (Equation F-9) and the average emission rate for the calendar year (Equation F-10), in lb/mmBtu:

$$E_q = \sum_{i=1}^{n} \frac{E_i}{n}$$

(Eq. F-9)

Where:

E_q = Quarterly average NO_x emission rate, lb/mmBtu.

E_i = Hourly average NO_x emission rate during unit operation, lb/mmBtu.

n = Number of hourly rates during calendar quarter.

$$E_a = \sum_{i=1}^{m} \frac{E_i}{m}$$

(Eq. F-10)

Where:

E_a = Average NO_x emission rate for the calendar year, lb/mmBtu.

E_i = Hourly average NO_x emission rate during unit operation, lb/mmBtu.

m = Number of hourly rates for which E_i is available in the calendar year.

App. F § 3.5

3.5 Round all NO_x emission rates to the nearest 0.001 lb/mmBtu.

App. F § 4

4. Procedures for CO_2 Mass Emissions

Use the following procedures to convert continuous emission monitoring system measurements of CO_2 concentration (percentage) and volumetric flow rate (scfh) into CO_2 mass emissions (in tons/day) when the owner or operator uses a CO_2 continuous emission monitoring system (consisting of a CO_2 or O_2 pollutant monitor) and a flow monitoring system to monitor CO_2

emissions from an affected unit.

App. F § 4.1

4.1 When CO_2 concentration is measured on a wet basis, use the following equation to calculate hourly CO_2 mass emissions rates (in tons/hr):

$$E_h = K\, C_h\, Q_h$$

(Eq. F-11)
Where:
E_h = Hourly CO_2 mass emission rate during unit operation, tons/hr.
K = 5.7×10^{-7} for CO_2, (tons/scf) /%CO_2.
C_h = Hourly average CO_2 concentration during unit operation, wet basis, either measured directly with a CO_2 monitor or calculated from wet-basis O_2 data using Equation F-14b, percent CO_2. ~~For boilers, a minimum concentration of 5.0 percent CO_2 may be substituted for the measured concentration when the hourly average concentration of CO_2 is < 5.0 percent CO_2, provided that this minimum concentration of 5.0 percent CO_2 is also used in the calculation of heat input for that hour. For stationary gas turbines, a minimum concentration of 1.0 percent CO_2 may be substituted for measured diluent gas concentration values during hours when the hourly average concentration of CO_2 is < 1.0 percent CO_2, provided that this minimum concentration of 1.0 percent CO_2 is also used in the calculation of heat input for that hour.~~
Q_h = Hourly average volumetric flow rate during unit operation, wet basis, scfh.

App. F § 4.2

4.2 When CO_2 concentration is measured on a dry basis, use Equation F-2 to calculate the hourly CO_2 mass emission rate (in tons/hr) with a K-value of 5.7×10^{-7} (tons/scf) percent CO_2, where E_h = hourly CO_2 mass emission rate, tons/hr and C_{hp} = hourly average CO_2 concentration in flue, dry basis, percent CO_2.

App. F § 4.3

4.3 Use the following equations to calculate total CO_2 mass emissions for each calendar quarter (Equation F-12) and for each calendar year (Equation F-13):

$$E_{CO_{2q}} = \sum_{h=1}^{H_R} E_h t_h$$

(Eq. F-12)
Where:
E_{CO2q} = Quarterly total CO_2 mass emissions, tons.
E_h = Hourly CO_2 mass emission rate, tons/hr.
t_h = Unit operating time, in hours or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).
H_R = Number of hourly CO_2 mass emission rates available during calendar quarter.

$$E_{CO_{2a}} = \sum_{q=1}^{4} E_{CO_{2q}}$$

(Eq. F-13)
Where,
E_{CO2a} = Annual total CO_2 mass emissions, tons.
E_{CO2q} = Quarterly total CO_2 mass emissions, tons.
q = Quarters for which E_{CO2q} are available during calendar year.

App. F § 4.4

4.4 For an affected unit, when the owner or operator is continuously monitoring O_2 concentration (in percent by volume) of flue gases using an O_2 monitor, use the equations and procedures in section 4.4.1 and 4.4.2 of this appendix to determine hourly CO_2 mass emissions (in tons).

App. F § 4.4.1

4.4.1 ~~Use~~ If the owner or operator elects to use data from an O_2 monitor to calculate CO_2

concentration, the appropriate F and F_C factors from section 3.3.5 of this appendix shall be used in one of the following equations (as applicable) to determine hourly average CO_2 concentration of flue gases (in percent by volume) from the measured hourly average O_2 concentration:

$$CO_{2d} = 100 \frac{F_c}{F} \frac{20.9 - O_{2d}}{20.9}$$ ~~$CO_{2d} = 100 \frac{F_c}{F} \frac{20.9 - O_{2d}}{20.9}$~~

(Eq. F-14a)

CO_{2d}= Hourly average CO_2 concentration during unit operation, percent by volume, dry basis.

F, F_C= F-factor or carbon-based F_c-factor from section 3.3.5 of this appendix.

20.9 = Percentage of O_2 in ambient air.

O_{2d} = Hourly average O_2 concentration during unit operation, percent by volume, dry basis. ~~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 heat input 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 heat input for that hour.~~

$$CO_{2w} = \frac{100}{20.9} \frac{F_c}{F} \left[20.9 \left(\frac{100 - \%H_2O}{100} \right) - O_{2w} \right]$$

~~$CO_{2w} = \frac{100}{20.9} \frac{F_c}{F} \left[20.9 \left(\frac{100 - \%H_2O}{100} \right) - O_{2w} \right]$~~

(Eq. F - 14b)

Where:

CO_{2w} = Hourly average CO_2 concentration during unit operation, percent by volume, wet basis.

O_{2w} = Hourly average O_2 concentration during unit operation, percent by volume, wet basis. ~~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 heat input 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 heat input for that hour.~~

F, F_c = F-factor or carbon-based F_C-factor from section 3.3.5 of this appendix.

20.9 = Percentage of O_2 in ambient air.

$\%H_2O$ = Moisture content of gas in the stack, percent.

For any hour where Equation F-14b results in a negative hourly average CO_2 value, 0.0% CO_{2w} shall be recorded as the average CO_2 value for that hour.

App. F § 4.4.2

4.4.2 Determine CO_2 mass emissions (in tons) from hourly average CO_2 concentration (percent by volume) using equation F-11 and the procedure in section 4.1, where O_2 measurements are on a wet basis, or using the procedures in section 4.2 of this appendix, where O_2 measurements are on a dry basis.

App. F § 5

5. Procedures for Heat Input

Use the following procedures to compute heat input rate to an affected unit (in mmBtu/hr or mmBtu/day):

App. F § 5.1

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.

App. F § 5.2

5.2 For an affected unit that has a flow monitor (or approved alternate monitoring system under subpart E of this part for measuring volumetric flow rate) and a diluent gas (O_2 or CO_2) monitor, use the recorded data from these monitors and one of the following equations to calculate hourly heat input rate (in mmBtu/hr).

App. F § 5.2.1

5.2.1 When measurements of CO_2 concentration are on a wet basis, use the following equation:

$$HI = Q_w \frac{1}{F_c} \frac{\% CO_{2w}}{100}$$

(Eq. F-15)

Where:

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

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

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

$\%CO_{2W}$ = Hourly concentration of CO_2during unit operation, percent CO_2 wet basis. ~~For boilers, a minimum concentration of 5.0 percent CO_2 may be substituted for the measured concentration when the hourly average concentration of CO_2 is < 5.0 percent CO_2, provided that this minimum concentration of 5.0 percent CO_2 is also used in the calculation of CO_2 mass emissions for that hour. For stationary gas turbines, a minimum concentration of 1.0 percent CO_2 may be substituted for measured diluent gas concentration values during hours when the hourly average concentration of CO_2 is < 1.0 percent CO_2, provided that this minimum concentration of 1.0 percent CO_2 is also used in the calculation of CO_2 mass emissions for that hour.~~

App. F § 5.2.2

5.2.2 When measurements of CO_2 concentration are on a dry basis, use the following equation:

$$HI = Q_h \left(\frac{100 - \% H_2O}{100 F_c} \right) \left(\frac{\% CO_{2d}}{100} \right)$$

(Eq. F-16)

Where:

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

Q_h = Hourly average volumetric flow rate during unit operation, wet basis, scfh.

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

$\%CO_{2d}$ = Hourly concentration of CO_2 during unit operation, percent CO_2 dry basis. ~~For boilers, a minimum concentration of 5.0 percent CO_2 may be substituted for the measured concentration when the hourly average concentration of CO_2 is < 5.0 percent CO_2, provided that this minimum concentration of 5.0 percent CO_2 is also used in the calculation of CO_2 mass emissions for that hour. For stationary gas turbines, a minimum concentration of 1.0 percent CO_2 may be substituted for measured diluent gas concentration values during hours when the hourly average concentration of CO_2 is < 1.0 percent CO_2, provided that this minimum concentration of 1.0 percent CO_2 is also used in the calculation of CO_2 mass emissions for that hour.~~

$\%H_2O$ = Moisture content of gas in the stack, percent.

App. F § 5.2.3

5.2.3 When measurements of O_2 concentration are on a wet basis, use the following equation:

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

(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.

For any hour where Equation F-17 results in a negative hourly heat input rate, 1.0 mmBtu/hr shall be recorded and reported as the heat input rate for that hour.

App. F § 5.2.4

5.2.4 When measurements of O_2 concentration are on a dry basis, use the following equation:

$$HI = Q_w \left(\frac{100 - \% H_2O}{100F} \right) \left(\frac{(20.9 - \% O_{2d})}{20.9} \right)$$

(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.~~

App. F § 5.3

5.3 Heat Input Summation (for Heat Input Determined Using a Flow Monitor and Diluent Monitor)

App. F, § 5.3.1

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

$$HI_q = \sum_{hour=1}^{n} HI_i \, t_i$$

(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).

App. F, § 5.3.2

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:

$$HI_c = \sum_{q=1}^{the\ current\ quarter} HI_q$$

(Eq. F-18b)
Where:
HI_c = Total heat input for the year to date, mmBtu.
HI_q = Total heat input for the quarter, mmBtu.

App. F § 5.4

5.4 [Reserved]

App. F § 5.5

5.5 For a gas-fired or oil-fired unit that does not have a flow monitor and is using the procedures specified in appendix D to this part to monitor SO_2 emissions or for any unit using a common stack for which the owner or operator chooses to determine heat input by fuel sampling and analysis, use the following procedures to calculate hourly heat input rate in mmBtu/hr. The procedures of section 5.5.3 of this appendix shall not be used to determine heat input from a coal unit that is required to comply with the provisions of this part for monitoring, recording, and reporting NO_x mass emissions under a State or federal NO_x mass emission reduction program.

App. F § 5.5.1

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

$$HI_o = M_o \frac{GCV_o}{10^6}$$

(Eq. F-19)
Where:
HI_o = Hourly heat input rate from oil, mmBtu/hr.
M_o = Mass rate of oil consumed per hour, as determined using procedures in appendix D to this part, in lb/hr, tons/hr, or kg/hr.
GCV_o = Gross calorific value of oil, as measured by ASTM D240-00 ~~D240-87~~ (Reapproved 1991), ASTM D5865-01ae1 ~~D2015-91~~, or ASTM D4809-00 ~~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).
10^6 = Conversion of Btu to mmBtu.

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

App. F § 5.5.2

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:

$$HI_g = \frac{(Q_g \times GCV_g)}{10^6}$$

(Eq. F-20)
Where:
HI_g = Hourly heat input rate from gaseous fuel, mmBtu/hour.
Q_g = Metered flow rate of gaseous fuel combusted during unit operation, hundred standard cubic feet per hour.

GCV_g = Gross calorific value of gaseous fuel, as determined by sampling (for each delivery for gaseous fuel in lots, for each daily gas sample for gaseous fuel delivered by pipeline, for each hourly average for gas measured hourly with a gas chromatograph, or for each monthly sample of pipeline natural gas, or as verified by the contractual supplier at least once every month pipeline natural gas is combusted, as specified in section 2.3 of appendix D to this part) using ASTM D1826-94 (1998)~~ D1826-88~~, ASTM D3588-98 ~~D3588-91~~, ASTM D4891-89 (2001), GPA Standard 2172-1996~~86~~ "Calculation of Gross Heating Value, Relative Density and Compressibility Factor for Natural Gas Mixtures from Compositional Analysis," or GPA Standard 2261-1999~~90~~ "Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography," Btu/100 scf (incorporated by reference under § 75.6).

10^6 = Conversion of Btu to mmBtu.

App. F § 5.5.3

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.)

App. F § 5.5.3.1

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 D2234-00e1~~ 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 D2234-00e1 ~~D2234-89~~ is optional, and coal samples may be taken weekly.)

App. F § 5.5.3.2

5.5.3.2 Use ASTM D2013-01~~ 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 D5865-01ae1, "Standard Test Method for Gross Calorific Value of Coal and Coke." ~~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.

App. F § 5.5.3.3

5.5.3.3 Calculate the heat input from coal using the following equation:

$$HI_c = M_c \frac{GCV_c}{500}$$

(Eq. F-21)

where:

HI_c = Daily heat input from coal, mmBtu/day.

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

GCV_c = Gross calorific value of coal sample, as measured by ASTM D3176-89 (1997)e1, or D5865 ae1 ~~D1989-92, D3286-91a, or D2015-91,~~ Btu/lb.

500 = Conversion of Btu/lb to mmBtu/ton.

App. F § 5.5.4

5.5.4 For units obtaining heat input values daily instead of hourly, apportion the daily heat input using the fraction of the daily steam load or daily unit operating load used each hour in order to obtain HI_i for use in the above equations. Alternatively, use the hourly mass of coal consumed in equation F-21.

App. F § 5.5.5

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.

App. F § 5.5.6

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.

App. F § 5.5.7

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.

App. F § 5.6

5.6 Heat Input Rate Apportionment for Units Sharing a Common Stack or Pipe

App. F § 5.6.1

5.6.1 Where applicable, the owner or operator of an affected unit that determines heat input rate at the unit level by apportioning the heat input monitored at a common stack or common pipe using megawatts shall apportion the heat input rate using the following equation:

$$HI_i = HI_{CS}\left(\frac{t_{CS}}{t_i}\right)\left[\frac{MW_i\, t_i}{\sum_{i=1}^{n} MW_i\, t_i}\right]$$

(Eq. F-21a)

Where:

HI_i = Heat input rate for a unit, mmBtu/hr.

HI_{CS} = Heat input rate at the common stack or pipe, mmBtu/hr.

MW_i = Gross electrical output, MWe.

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

t_{CS} = Common stack or common pipe operating time, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

n = Total number of units using the common stack or pipe.

i = Designation of a particular unit.

App. F § 5.6.2

5.6.2 Where applicable, the owner or operator of an affected unit that determines the heat input rate at the unit level by apportioning the heat input rate monitored at a common stack or common pipe using steam load shall apportion the heat input rate using the following equation:

$$HI_i = HI_{CS}\left(\frac{t_{CS}}{t_i}\right)\left[\frac{SF_i\, t_i}{\sum_{i=1}^{n} SF_i\, t_i}\right]$$

(Eq. F-21b)

Where:

HI_i = Heat input rate for a unit, mmBtu/hr.

HI_{CS} = Heat input rate at the common stack or pipe, mmBtu/hr.

SF = Gross steam load, lb/hr, or mmBtu/hr.

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

t_{CS} = Common stack or common pipe operating time, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

n = Total number of units using the common stack or pipe.

i = Designation of a particular unit.

App. F § 5.7

5.7 Heat Input Rate Summation for Units with Multiple Stacks or Pipes

The owner or operator of an affected unit that determines the heat input rate at the unit level by summing the heat input rates monitored at multiple stacks or multiple pipes shall sum the heat input rates using the following equation:

$$HI_{Unit} = \frac{\sum_{s=1}^{n} HI_s\, t_s}{t_{Unit}}$$

(Eq. F-21c)

Where:

HI_{Unit} = Heat input rate for a unit, mmBtu/hr.

HI_s = Heat input rate for the individual stack, duct, or pipe, mmBtu/hr.

t_{Unit} = Unit operating time, hour or fraction of the hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

t_s = Operating time for the individual stack or pipe, hour or fraction of the hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

s = Designation for a particular stack, duct, or pipe.

App. F § 5.8

5.8 *Alternate Heat Input Apportionment for Common Pipes*

As an alternative to using Equation F-21a or F-21b in section 5.6 of this appendix, the owner or operator may apportion the heat input rate at a common pipe to the individual units served by the common pipe based on the fuel flow rate to the individual units, as measured by uncertified fuel flowmeters. This option may only be used if a fuel flowmeter system that meets the requirements of appendix D to this part is installed on the common pipe. If this option is used, determine the unit heat input rates using the following equation:

$$HI_i = HI_{CP}\left(\frac{t_{CP}}{t_i}\right)\left[\frac{FF_i\, t_i}{\sum_{i=1}^{n} FF_i\, t_i}\right]$$

(Eq. F-21d)

Where:

HI_i = Heat input rate for a unit, mmBtu/hr.

HI_{CP} = Heat input rate at the common pipe, mmBtu/hr.

FF_i = Fuel flow rate to a unit, gal/min, 100 scfh, or other appropriate units.

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

t_{CP} = Common pipe operating time, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

n = Total number of units using the common pipe.

I = Designation of a particular unit.

App. F § 6

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.

App. F § 7

7. Procedures for SO_2 Mass Emissions~~ at Units with~~, using default SO_2 ~~Continuous Emission Monitoring Systems During the Combustion of Pipeline Natural Gas or Natural Gas~~Emission Rates and Heat Input Measured by CEMS

~~The owner or operator shall use the following equation to calculate hourly SO_2 mass emissions as allowed for units with SO_2 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_2 emissions are determined in accordance with § 75.11(e)(1).~~

$$\cancel{E_h = (ER)(HI)}$$

The owner or operator shall use Equation F-23 to calculate hourly SO_2 mass emissions in accordance with § 75.11(e)(1) during the combustion of gaseous fuel, for a unit that uses a flow monitor and a diluent gas monitor to measure heat input, and that qualifies to use a default SO_2 emission rate under section 2.3.1.1, 2.3.2.1.1, or 2.3.6(b) of appendix D to this part. Equation F-23 may also be applied to the combustion of solid or liquid fuel that meets the definition of very low sulfur fuel in § 72.2 of this chapter, combinations of such fuels, or mixtures of such fuels with gaseous fuel, if the owner or operator has received approval from the Administrator under §75.66 to use a site-specific default SO_2 emission rate for the fuel or mixture of fuels.

$$E_h = (ER)\,(HI)$$

(Eq. F-23)

Where,

E_h = Hourly SO_2 mass emission rate, lb/hr.

ER = Applicable SO_2 default emission rate for gaseous fuel combustion, from section 2.3.1.1, 2.3.2.1.1, or 2.3.6(b) of appendix D to this part, or other default SO_2 emission rate for the combustion of very low sulfur liquid or solid fuel, combinations of such fuels, or mixtures of such fuels with gaseous fuel, as approved by the Administrator under §75.66, lb/mmBtu. ~~from section 2.3.1.1 or 2.3.2.1.1 of appendix D to this part, lb/mmBtu.~~

HI = Hourly heat input rate, ~~as~~ determined using the procedures ~~of~~ in section 5.2 of this appendix, mmBtu/hr.

App. F § 8

8. Procedures for NO_x Mass Emissions

The owner or operator of a unit that is required to monitor, record, and report NO_x mass emissions under a State or federal NO_x mass emission reduction program must use the procedures in section 8.1, 8.2, or 8.3 of this appendix, as applicable, to account for hourly NO_x mass emissions, and the procedures in section 8.4 of this appendix to account for quarterly, seasonal, and annual NO_x mass emissions to the extent that the provisions of subpart H of this part are adopted as requirements under such a program.

App. F § 8.1

8.1 The owner or operator may use the hourly NO_x emission rate and the hourly heat input rate to ~~Use the following procedures to~~ calculate ~~hourly~~ the NO_x mass emissions in ~~lbs~~ pounds or the NO_x mass emission rate in pounds per hour (as required by the applicable reporting format) for each ~~the~~ unit or stack operating hour ~~using hourly NO_x emission rate and heat input~~as follows:~~.~~

App. F § 8.1.1

8.1.1 If both NO_x emission rate and heat input rate are monitored at the same unit or stack level

(e.g, the NO_x emission rate value and heat input rate value both represent all of the units exhausting to the common stack), ~~use the following equation~~then (as required by the applicable reporting format) either:

(a) Use Equation F-24 to calculate the hourly NO_x mass emissions (lb).

$$M_{(NOx)_h} = ER_{(NOx)_h} HI_h t_h$$

(Eq. F-24)
Where:
$M_{(NOx)h}$ = NO_x mass emissions in lbs for the hour.
$ER_{(NOx)h}$ = Hourly average NO_x emission rate for hour h, lb/mmBtu, from section 3 of this appendix, from method 19 of appendix A to part 60 of this chapter, or from section 3.3 of appendix E to this part. (Include bias-adjusted NOx emission rate values, where the bias-test procedures in appendix A to this part shows a bias-adjustment factor is necessary.)
HI_h = Hourly average heat input rate for hour h, mmBtu/hr. (Include bias-adjusted flow rate values, where the bias-test procedures in appendix A to this part shows a bias-adjustment factor is necessary.)
t_h = Monitoring location operating time for hour h, in hours or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator). If the combined NO_x emission rate and heat input are monitored for all of the units in a common stack, the monitoring location operating time is equal to the total time when any of those units was exhausting through the common stack; or

(b) Use Equation F-24a to calculate the hourly NO_x mass emission rate (lb/hr).

$$E_{(NOx)_h} = ER_{(NOx)_h} HI_h$$

(Eq. F-24a)
Where:
$E_{(NOx)h}$ = NO_x mass emissions rate in lbs/hr for the hour.
$ER_{(NOx)h}$= Hourly average NO_x emission rate for hour h, lb/mmBtu, from section 3 of this appendix, from method 19 of appendix A to part 60 of this chapter, or from section 3.3 of appendix E to this part. (Include bias-adjusted NOx 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.)

App. F § 8.1.2

8.1.2 If NO_x emission rate is measured at a common stack and heat input is measured at the unit level, sum the hourly heat inputs at the unit level according to the following formula:

$$HI_{CS} = \frac{\sum_{u=1}^{p} HI_u t_u}{t_{CS}}$$

(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). (For each hour, t_{cs} is the total time during which one or more of the units which exhaust through the common stack operate.).

HI_u = Hourly average heat input rate for hour h for the unit, mmBtu/hr.

t_u = Unit operating time for hour h, in hours or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

p = Number of units that exhaust through the common stack.

u = Designation of a particular unit.

Use the hourly heat input rate at the common stack level and the hourly average NO_x emission rate at the common stack level and the procedures in section 8.1.1 of this appendix to determine the hourly NO_x mass emissions at the common stack.

App. F § 8.1.3

8.1.3 If a unit has multiple ducts and NO_x emission rate is only measured at one duct, use the NO_x emission rate measured at the duct, the heat input measured for the unit, and the procedures in section 8.1.1 of this appendix to determine NO_x mass emissions.

App. F § 8.1.4

8.1.4 If a unit has multiple ducts and NO_x emission rate is measured in each duct, heat input shall also be measured in each duct and the procedures in section 8.1.1 of this appendix shall be used to determine NO_x mass emissions.

App. F § 8.2

8.2 Alternatively, the owner or operator may use the hourly NO_x concentration (as measured by a NO_x concentration monitoring system) and the hourly stack gas volumetric flow rate to calculate the NO_x mass emission rate (lb/hr) for each unit or stack operating hour, in accordance with section 8.2.1 or 8.2.2 of this appendix (as applicable). If the hourly NO_x mass emissions are to be reported in lb, Equation F-26c in section 8.3 of this appendix shall be used to convert the hourly NO_x mass emission rates to hourly NO_x mass emissions (lb). ~~If a unit calculates NO_x mass emissions using a NO_x concentration monitoring system and a flow monitoring system, calculate hourly 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_2" with "NO_x" and replace the value of K with 1.194×10^{-7} (lb NO_x/scf)/ppm. (Include bias-adjusted flow rate or NO_x concentration values, where the bias-test procedures in appendix A to this part shows a bias-adjustment factor is necessary.)~~

App. F § 8.2.1

8.2.1 When the NO_x concentration monitoring system measures on a wet basis, first calculate the hourly NO_x mass emission rate (in lb/hr) during unit (or stack) operation, using Equation F-26a. (Include bias-adjusted flow rate or NO_x concentration values, where the bias-test procedures in appendix A to this part shows a bias-adjustment factor is necessary.)

$$E_{(NOx)_h} = K\ C_{hw}\ Q_h$$

(Eq. F-26a)

Where:

$E_{(NOx)h}$ = NO_x mass emission rate in lb/hr.

K = 1.194×10^{-7} for NO_x, (lb/scf)/ppm.

C_{hw} = Hourly average NO_x concentration during unit operation, wet basis, ppm.

Q_h = Hourly average volumetric flow rate during unit operation, wet basis, scfh.

App. F § 8.2.2

8.2.2 When NO_x mass emissions are determined using a dry basis NO_x concentration monitoring system and a wet basis flow monitoring system, first calculate hourly NO_x mass emission rate (in lb/hr) during unit (or stack) operation, using Equation F-26b. (Include bias-adjusted flow rate or NO_x concentration values, where the bias-test procedures in appendix A to this part shows a bias-adjustment factor is necessary.)

$$E_{(NOx)_h} = K\ C_{hd}\ Q_h \frac{(100 - \%H_2O)}{(100)}$$

(Eq. F-26b)

Where:
$E_{(NOx)h}$ = NO_x mass emission rate, lb/hr.
K = 1.194×10^{-7} for NO_x, (lb/scf)/ppm.
C_{hd} = Hourly average NO_x concentration during unit operation, dry basis, ppm.
Q_h = Hourly average volumetric flow rate during unit operation, wet basis, scfh
$\%H_2O$ = Hourly average stack moisture content during unit operation, percent by volume.

App. F § 8.3

8.3 ~~If a unit calculates~~ When hourly NO_x mass emissions are reported in pounds and are determined using a NO_x concentration monitoring system and a flow monitoring system, calculate NO_x mass emissions (lb) for ~~the~~ each unit or stack operating hour ~~(lb)~~ by multiplying the hourly NO_x mass emission rate ~~during unit operation~~ (lb/hr) by the unit operating time for the hour ~~during the hour~~, as follows:

$$M_{(NO_x)_h} = E_h t_h$$

(Eq. F-26c)
Where:
$M_{(NOx)h}$ = NO_x mass emissions ~~in lbs~~ for the hour, lb.
E_h = Hourly NO_x mass emission rate during unit (or stack) operation from Equation F-26a in section 8.2.1 of this appendix or Equation F-26b in section 8.2.2 of this appendix (as applicable), lb/hr. ~~, lb/hr, from section 8.2 of this appendix.~~
t_h = ~~Monitoring location operating time for hour h,~~ Unit operating time or stack operating time (as defined in §72.2 of this chapter) for hour "h", in hours or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator). ~~If the 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.~~

App. F § 8.4

8.4 Use the following procedures to calculate quarterly, cumulative ozone season, and cumulative yearly NO_x mass emissions, in tons:

(a) When hourly NO_x mass emissions are reported in lb, use Eq. F-27.

$$M_{(NO_x)_{time\ period}} = \frac{\sum_{h=1}^{p} M_{(NO_x)_h}}{2000}$$

(Eq. F-27)
Where:
$M_{(NOx)time\ period}$ = NO_x mass emissions in tons for the given time period (quarter, cumulative ozone season, cumulative year-to-date).
$M_{(NOx)h}$ = NO_x mass emissions in lbs for the hour.
p = The number of hours in the given time period (quarter, cumulative ozone season, cumulative year-to-date).

(b) When hourly NO_x mass emission rate is reported in lb/hr, use Eq. F-27a.

$$M_{(NO_x)_{time\ period}} = \frac{\sum_{h=1}^{p} E_{(NOx)h} t_h}{2000}$$

(Eq. F-27a)
Where:

$M_{(NOx)time\ period}$ = NO_x mass emissions in tons for the given time period (quarter, cumulative ozone season, cumulative year-to-date).

$E_{(NOx)h}$ = NO_x mass emission rate in lb/hr for the hour.

p = The number of hours in the given time period (quarter, cumulative ozone season, cumulative year-to-date).

t_h = Monitoring location operating time for hour h, in hours or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

App. F § 8.5 *8.5 Specific provisions for monitoring NO_x mass emissions from common stacks.*

The owner or operator of a unit utilizing a common stack may account for NO_x mass emissions using either of the following methodologies, if the provisions of subpart H are adopted as requirements of a State or federal NO_x mass reduction program:

App. F § 8.5.1 8.5.1 The owner or operator may determine both NO_x emission rate and heat input at the common stack and use the procedures in section 8.1.1 of this appendix to determine hourly NO_x mass emissions at the common stack.

App. F § 8.5.2 8.5.2 The owner or operator may determine the NO_x emission rate at the common stack and the heat input at each of the units and use the procedures in section 8.1.2 of this appendix to determine the hourly NO_x mass emissions at each unit.

App. F § 9 **9. Procedures for Hg Mass Emissions**

App. F § 9.1 *9.1* Use the procedures in this section to calculate the hourly Hg mass emissions (in ounces) at each monitored location, for the affected unit or group of units that discharge through a common stack.

App. F § 9.1.1 9.1.1 To determine the hourly Hg mass emissions when using a Hg concentration monitoring system that measures on a wet basis and a flow monitor, use the following equation:

$$M_h = K\, C_h\, Q_h\, t_h$$

(Eq. F-28)

Where:

M_h = Hg mass emissions for the hour, rounded off to three decimal places, (ounces).

K = Units conversion constant, 9.978×10^{-10} oz-scm/µg-scf

C_h = Hourly Hg concentration, wet basis, adjusted for bias if the bias-test procedures in appendix A to this part show that a bias-adjustment factor is necessary, (µg/wscm).

Q_h = Hourly stack gas volumetric flow rate, adjusted for bias, where the bias-test procedures in appendix A to this part shows a bias-adjustment factor is necessary, (scfh)

t_h = Unit or stack operating time, as defined in § 72.2, (hr)

App. F § 9.1.2 9.1.2 To determine the hourly Hg mass emissions when using a Hg concentration monitoring

system that measures on a dry basis or a sorbent trap monitoring system and a flow monitor, use the following equation:

$$M_h = K C_h Q_h t_h (1 - B_{ws})$$

(Eq. F-29)

Where:
M_h = Hg mass emissions for the hour, rounded off to three decimal places, (ounces).
K = Units conversion constant, 9.978×10^{-10} oz-scm/µg-scf
C_h = Hourly Hg concentration, dry basis, adjusted for bias if the bias-test procedures in appendix A to this part show that a bias-adjustment factor is necessary, (µg/dscm). For sorbent trap systems, a single value of C_h (i.e., a flowproportional average concentration for the data collection period), is applied to each hour in the data collection period, for a particular pair of traps.
Q_h = Hourly stack gas volumetric flow rate, adjusted for bias, where the bias-test procedures in appendix A to this part shows a bias-adjustment factor is necessary, (scfh)
B_{ws} = Moisture fraction of the stack gas, expressed as a decimal (equal to % H2O 100)
t_h = Unit or stack operating time, as defined in § 72.2, (hr)

App. F § 9.1.3

9.1.3 For units that are demonstrated under § 75.81(d) to emit less than 464 ounces of Hg per year, and for which the owner or operator elects not to continuously monitor the Hg concentration, calculate the hourly Hg mass emissions using Equation F–28 in section 9.1.1 of this appendix, except that "C_h" shall be the applicable default Hg concentration from §75.81(c), (d), or (e), expressed in µg/scm. Correction for the stack gas moisture content is not required when this methodology is used.

App. F § 9.2

9.2 Use the following equation to calculate quarterly and year-to-date Hg mass emissions in ounces:

$$M_{\text{time period}} = \sum_{h}^{n} M_h$$

(Eq. F-30)
Where:
$M_{\text{time period}}$ = Hg mass emissions for the given time period i.e., quarter or year-to-date, rounded to the nearest thousandth, (ounces).
M_h = Hg mass emissions for the hour, rounded to three decimal places, (ounces).
n = The number of hours in the given time period (quarter or year-to-date).

App. F § 9.3

9.3 If heat input rate monitoring is required, follow the applicable procedures for heat input apportionment and summation in sections 5.3, 5.6 and 5.7 of this appendix.

App. F § 10

10. Moisture Determination from Wet and Dry O_2 Readings

If a correction for the stack gas moisture content is required in any of the emissions or heat input calculations described in this appendix, and if the hourly moisture content is determined from wet- and dry-basis O_2 readings, use Equation F-31 to calculate the percent moisture, unless a "K" factor or other mathematical algorithm is developed as described in section 6.5.7(a) of appendix A to this part:

$$\%H_2O = \frac{(O_{2d} - O_{2w})}{O_{2d}} \times 100$$

(Eq. F-31)
Where:
% H_2O = Hourly average stack gas moisture content, percent H_2O
O_{2d} = Dry-basis hourly average oxygen concentration, percent O_2
O_{2w} = Wet-basis hourly average oxygen concentration, percent O_2

Appendix G to Part 75 -- Determination of CO_2 Emissions

App. G § 1

1. Applicability

The procedures in this appendix may be used to estimate CO_2 mass emissions discharged to the atmosphere (in tons/day) as the sum of CO_2 emissions from combustion and, if applicable, CO_2 emissions from sorbent used in a wet flue gas desulfurization control system, fluidized bed boiler, or other emission controls.

App. G § 2

2. Procedures for Estimating CO_2 Emissions from Combustion

Use the following procedures to estimate daily CO_2 mass emissions from the combustion of fossil fuels. The optional procedure in section 2.3 of this appendix may also be used for an affected gas-fired unit. For an affected unit that combusts any nonfossil fuels (e.g., bark, wood, residue, or refuse), either use a CO_2 continuous emission monitoring system or apply to the Administrator for approval of a unit-specific method for determining CO_2 emissions.

App. G § 2.1

2.1 Use the following equation to calculate daily CO_2 mass emissions (in tons/day) from the combustion of fossil fuels. Where fuel flow is measured in a common pipe header (i.e., a pipe carrying fuel for multiple units), the owner or operator may use the procedures in section 2.1.2 of appendix D of this part for combining or apportioning emissions, except that the term "SO_2 mass emissions" is replaced with the term "CO_2 mass emissions."

$$W_{CO_2} = \frac{(MW_C + MW_{O_2}) \, x \, W_C}{2{,}000 \, MW_C}$$

(Eq. G-1)
Where:
W_{co2} = CO_2 emitted from combustion, tons/day.
MW_c = Molecular weight of carbon (12.0).
Mw_{o2} = Molecular weight of oxygen (32.0)
W_c = Carbon burned, lb/day, determined using fuel sampling and analysis and fuel feed rates.

App. G § 2.1.1

2.1.1 Collect at least one fuel sample during each week that the unit combusts coal, one sample per each shipment or delivery for oil and diesel fuel, one fuel sample for each delivery for gaseous

fuel in lots, one sample per day or per hour (as applicable) for each gaseous fuel that is required to be sampled daily or hourly for gross calorific value under section 2.3.5.6 of appendix D to this part, and one sample per month for each gaseous fuel that is required to be sampled monthly for gross calorific value under section 2.3.4.1 or 2.3.4.2 of appendix D to this part. Collect coal samples from a location in the fuel handling system that provides a sample representative of the fuel bunkered or consumed during the week.

App. G § 2.1.2

2.1.2 Determine the carbon content of each fuel sample using one of the following methods: ASTM D3178-89 (1997) or ASTM 5373-93 for coal; ASTM D5291-01 ~~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 D3238-95 (2000)e1 ~~D3238-90~~ and either ASTM D2502-92 (1996) ~~D2502-87~~ or ASTM D2503-92 (1997) ~~D2503-82 (Reapproved 1987)~~ for oil; and computations based on ASTM D1945-96 (2001) ~~D1945-91~~ or ASTM D1946-90 (2000) for gas.

App. G § 2.1.3

2.1.3 Use daily fuel feed rates from company records for all fuels and the carbon content of the most recent fuel sample under this section to determine tons of carbon per day from combustion of each fuel. (All ASTM methods are incorporated by reference under § 75.6.) Where more than one fuel is combusted during a calendar day, calculate total tons of carbon for the day from all fuels.

App. G § 2.2

2.2 For an affected coal-fired unit, the estimate of daily CO_2 mass emissions given by equation G-1 may be adjusted to account for carbon retained in the ash using the procedures in either section 2.2.1 through 2.2.3 or section 2.2.4 of this appendix.

App. G § 2.2.1

2.2.1 Determine the ash content of the weekly sample of coal using ASTM D3174-00 ~~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).

App. G § 2.2.2

2.2.2 Sample and analyze the carbon content of the fly-ash according to ASTM D3178-89 (1997), "Standard Test Methods for Carbon and Hydrogen in the Analysis Sample of Coal and Coke" (incorporated by reference under § 75.6 of this part).

App. G § 2.2.3

2.2.3 Discount the estimate of daily CO_2 mass emissions from the combustion of coal given by equation G-1 by the percent carbon retained in the ash using the following equation:

$$W_{NCO2} = W_{CO2} - \left(\frac{MW_{CO2}}{MW_C}\right)\left(\frac{A\%}{100}\right)\left(\frac{C\%}{100}\right)W_{COAL}$$

(Eq. G-2)

where,

W_{NCO2} = Net CO_2 mass emissions discharged to the atmosphere, tons/day.
W_{CO2} = Daily CO_2 mass emissions calculated by equation G-1, tons/day.
MW_{C02} = Molecular weight of carbon dioxide (44.0).
MW_c = Molecular weight of carbon (12.0).
A% = Ash content of the coal sample, percent by weight.
C% = Carbon content of ash, percent by weight.
W_{COAL} = Feed rate of coal from company records, tons/day.

App. G § 2.2.4

2.2.4 The daily CO_2 mass emissions from combusting coal may be adjusted to account for carbon retained in the ash using the following equation:

$$W_{NCO2} = .99\, W_{CO2}$$

(Eq. G-3)

where:

W_{NCO2} = Net CO_2 mass emissions from the combustion of coal discharged to the atmosphere, tons/day.
.99 = Average fraction of coal converted into CO_2 upon combustion.

WCO_2 = Daily CO_2 mass emissions from the combustion of coal calculated by equation G-1, tons/day.

App. G § 2.3

2.3 In lieu of using the procedures, methods, and equations in section 2.1 of this appendix, the owner or operator of an affected gas-fired or oil-fired unit (as defined under § 72.2 of this chapter) may use the following equation and records of hourly heat input to estimate hourly CO_2 mass emissions (in tons).

$$W_{CO_2} = \frac{F_c \, x \, H \, x \, U_f \, x \, MW_{CO_2}}{2000}$$

(Eq. G-4)
Where:
WCO_2 = CO_2 emitted from combustion, tons/hr.
MW_{C02} = Molecular weight of carbon dioxide, 44.0 lb/lb-mole.
F_c = Carbon based F-factor, 1040 scf/mmBtu for natural gas; 1,420 scf/mmBtu for crude, residual, or distillate oil; and calculated according to the procedures in section 3.3.5 of appendix F to this part for other gaseous fuels.
H = Hourly heat input in mmBtu, as calculated using the procedures in section 5 of appendix F of this part.
Uf = 1/385 scf CO2/lb-mole at 14.7 psia and 68 °F.

App. G § 3

3. Procedures for Estimating CO_2 Emissions from Sorbent

When the affected unit has a wet flue gas desulfurization system, is a fluidized bed boiler, or uses other emission controls with sorbent injection, use either a CO_2 continuous emission monitoring system or an O_2 monitor and a flow monitor, or use the procedures, methods, and equations in sections 3.1 through 3.2 of this appendix to determine daily CO_2 mass emissions from the sorbent (in tons).

App. G § 3.1

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.

App. G § 3.1.1

3.1.1 Use the following equation to estimate daily CO_2 mass emissions from sorbent (in tons).

$$SE_{CO_2} = W_{CaCO_3} \; F_u \; \frac{MW_{CO_2}}{MW_{CaCO_3}}$$

(Eq. G-5)
where,
SE_{CO2} = CO_2 emitted from sorbent, tons/day.
W_{CaCO3} = $CaCO_3$ used, tons/day.
F_u = 1.00, the calcium to sulfur stoichiometric ratio.
MW_{CO2} = Molecular weight of carbon dioxide (44).
MW_{CaCO3} = Molecular weight of calcium carbonate (100).

App. G § 3.1.2

3.1.2 In lieu of using Equation G-5, any owner or operator who operates and maintains a certified SO_2-diluent continuous emission monitoring system (consisting of an SO_2 pollutant concentration monitor and an O_2 or CO_2 diluent gas monitor), for measuring and recording SO_2 emission rate (in lb/mmBtu) at the outlet to the emission controls and who uses the applicable procedures, methods, and equations such as those in EPA Method 19 in appendix A to part 60 of this chapter to estimate the SO_2 emissions removal efficiency of the emission controls, may use the following equations to estimate daily CO_2 mass emissions from sorbent (in tons).

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

(Eq. G-6)
Where,
SE_{CO2} = CO_2 emitted from sorbent, tons/day.
MW_{CO2} = Molecular weight of carbon dioxide (44).
MW_{SO2} = Molecular weight of sulfur dioxide (64).
W_{SO2} = Sulfur dioxide removed, lb/day, as calculated below using Eq. G-7.
F_u = 1.0, the calcium to sulfur stoichiometric ratio.

and

$$W_{SO_2} = SO_{20} \frac{\% R}{(100 - \% R)}$$

(Eq. G-7)
Where,
WSO_2 = Weight of sulfur dioxide removed, lb/day.
SO_{20} = SO_2 mass emissions monitored at the outlet, lb/day, as calculated using the equations and procedures in section 2 of appendix F of this part.
%R = Overall percentage SO_2 emissions removal efficiency, calculated using such equations as those in EPA Method 19 in appendix A to part 60 of this chapter, and using daily instead of annual average emission rates.

App. G § 3.2

3.2 When a sorbent material other than limestone is used, modify the equations, methods, and procedures in Section 3.1 of this appendix as follows to estimate daily CO_2 mass emissions from sorbent (in tons).

3.2.1 Determine a site-specific value for F_u, defined as the ratio of the number of moles of CO_2 released upon capture of one mole of SO_2, using methods and procedures satisfactory to the Administrator. Use this value of F_u (instead of 1.0) in either equation G-5 or equation G-6.

3.2.2 When using equation G-5, replace MW_{CaCO3}, the molecular weight of calcium carbonate, with the molecular weight of the sorbent material that participates in the reaction to capture SO_2 and that releases CO_2, and replace W_{CaCO3}, the amount of calcium carbonate used (in tons/day), with the amount of sorbent material used (in tons/day).

App. G § 4

4. Procedures for Estimating Total CO_2 Emissions

When the affected unit has a wet flue gas desulfurization system, is a fluidized bed boiler, or uses other emission controls with sorbent injection, use the following equation to obtain total daily CO_2 mass emissions (in tons) as the sum of combustion- related emissions and sorbent-related emissions.

$$W_t = W_{CO2} + SE_{CO2}$$

(Eq. G-8)
Where,
W_t = Estimated total CO_2 mass emissions, tons/day.
W_{CO2} = CO_2 emitted from fuel combustion, tons/day.
SE_{CO2} = CO_2 emitted from sorbent, tons/day.

App. G § 5

5. Missing Data Substitution Procedures for Fuel Analytical Data

Use the following procedures to substitute for missing fuel analytical data used to calculate CO_2 mass emissions under this appendix.

App. G § 5.1 *5.1 [Reserved]*

5.1.1 [Reserved]

5.1.2 [Reserved]

App. G § 5.2 *5.2 Missing Carbon Content Data*

Use the following procedures to substitute for missing carbon content data.

App. G § 5.2.1 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.

App. G § 5.2.2 5.2.2 The missing data values in Table G-1 shall be reported whenever the results of a required sample of fuel carbon content are either missing or invalid. The substitute data value shall be used until the next valid carbon content sample is obtained.

TABLE G-1. -- MISSING DATA SUBSTITUTION PROCEDURES FOR MISSING CARBON CONTENT DATA

Parameter	Missing data value
Oil and coal carbon content	Most recent, previous carbon content value available for that type of coal, grade of oil, or default value, in this table.
Gas carbon content	Most recent, previous carbon content value available for that type of gaseous fuel, or default value, in this table.
Default coal carbon content	Anthracite: 90.0 percent.
	Bituminous: 85.0 percent.
	Subbituminous/Lignite: 75.0 percent.
Default oil carbon content	90.0 percent.
Default gas carbon content	Natural gas: 75.0 percent.
	Other gaseous fuels: 90.0 percent.

App. G § 5.3 *5.3 Gross Calorific Value Data*

For a gas-fired unit using the procedures of section 2.3 of this appendix to determine CO_2 emissions, substitute for missing gross calorific value data used to calculate heat input by following the missing data procedures for gross calorific value in section 2.4 of appendix D to this part.

Appendix H to Part 75 -- Revised Traceability Protocol No. 1

[Reserved]

Appendix I to Part 75 -- Optional F-Factor/Fuel Flow Method

[Reserved]

Appendix J to Part 75 -- Compliance Dates for Revised Recordkeeping Requirements and Missing Data Procedures

[Reserved]

Appendix K to Part 75 -- Quality Assurance and Operating Procedures for Sorbent Trap Monitoring Systems

App. K § 1

1. Scope and Application

This appendix specifies sampling, and analytical, and quality-assurance criteria and procedures for the performance-based monitoring of vapor-phase mercury (Hg) emissions in combustion flue gas streams, using a sorbent trap monitoring system (as defined in § 72.2 of this chapter). The principle employed is continuous sampling using in-stack sorbent media coupled with analysis of the integrated samples. The performance-based approach of this appendix allows for use of various suitable sampling and analytical technologies while maintaining a specified and documented level of data quality through performance criteria. Persons using this appendix should have a thorough working knowledge of Methods 1, 2, 3, 4 and 5 in appendices A– 1 through A–3 to part 60 of this chapter, as well as the determinative technique selected for analysis.

App. K § 1.1

1.1 Analytes

The analyte measured by these procedures and specifications is total vapor-phase Hg in the flue gas, which represents the sum of elemental Hg (Hg0, CAS Number 7439–97–6) and oxidized forms of Hg, in mass concentration units of micrograms per dry standard cubic meter (µg/dscm).

App. K § 1.2

1.2 Applicability

These performance criteria and procedures are applicable to monitoring of vapor-phase Hg emissions under relatively low-dust conditions (i.e., sampling in the stack after all pollution control devices), from coal-fired electric utility steam generators which are subject to subpart I of this part. Individual sample collection times can range from 30 minutes to several days in duration, depending on the Hg concentration in the stack. The monitoring system must achieve the performance criteria specified in Section 8 of this appendix and the sorbent media capture ability must not be exceeded. The sampling rate must be maintained at a constant proportion to the total stack flowrate to ensure representativeness of the sample collected. Failure to achieve certain performance criteria will result in invalid Hg emissions monitoring data.

App. K § 2

2. Principle

Known volumes of flue gas are extracted from a stack or duct through paired, in-stack, pre-spiked sorbent media traps at an appropriate nominal flow rate. Collection of Hg on the sorbent media in the stack mitigates potential loss of Hg during transport through a probe/sample line. Paired train sampling is required to determine measurement precision and verify acceptability of the measured emissions data. The sorbent traps are recovered from the sampling system, prepared for analysis, as needed, and analyzed by any suitable determinative technique that can meet the performance criteria. A section of each sorbent trap is spiked with Hg^0 prior to sampling. This section is analyzed separately and the recovery value is used to correct the individual Hg sample for measurement bias.

App. K § 3

3. Clean Handling and Contamination

To avoid Hg contamination of the samples, special attention should be paid to cleanliness during transport, field handling, sampling, recovery, and laboratory analysis, as well as during

preparation of the sorbent cartridges. Collection and analysis of blank samples (field, trip, lab) is useful in verifying the absence of contaminant Hg.

App. K § 4 **4. Safety**

App. K § 4.1 *4.1 Site Hazards*

Site hazards must be thoroughly considered in advance of applying these procedures/specifications in the field; advance coordination with the site is critical to understand the conditions and applicable safety policies. At a minimum, portions of the sampling system will be hot, requiring appropriate gloves, long sleeves, and caution in handling this equipment.

App. K § 4.2 *4.2 Laboratory safety policies*

Laboratory safety policies should be in place to minimize risk of chemical exposure and to properly handle waste disposal. Personnel shall wear appropriate laboratory attire according to a Chemical Hygiene Plan established by the laboratory.

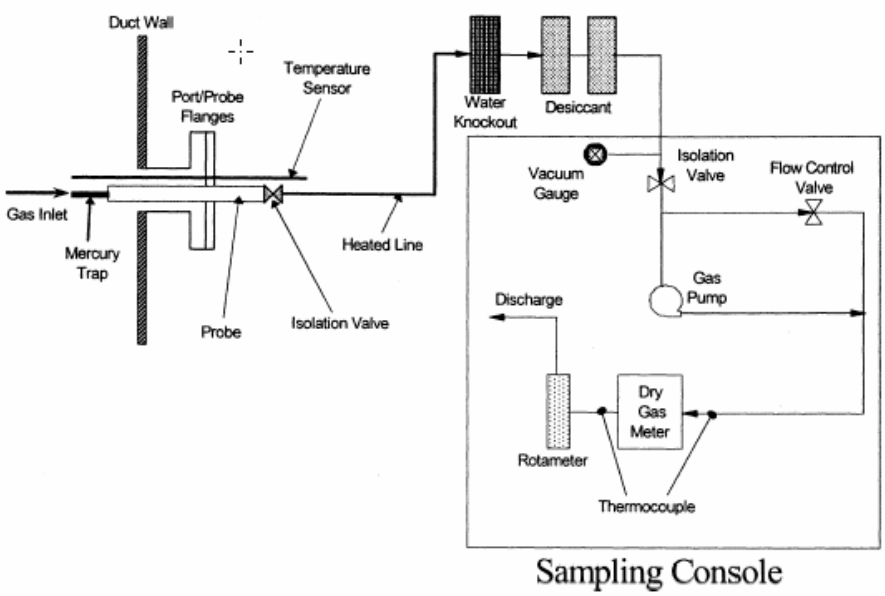
App. K § 4.3 *4.3 Toxicity or carcinogenicity*

The toxicity or carcinogenicity of any reagents used must be considered. Depending upon the sampling and analytical technologies selected, this measurement may involve hazardous materials, operations, and equipment and this appendix does not address all of the safety problems associated with implementing this approach. It is the responsibility of the user to establish appropriate safety and health practices and determine the applicable regulatory limitations prior to performance. Any chemical should be regarded as a potential health hazard and exposure to these compounds should be minimized. Chemists should refer to the Material Safety Data Sheet (MSDS) for each chemical used.

App. K § 4.4 *4.4 Wastes*

Any wastes generated by this procedure must be disposed of according to a hazardous materials management plan that details and tracks various waste streams and disposal procedures.

Figure K-1. Typical Sorbent Trap Monitoring System



App. K § 5 **5. Equipment and Supplies**

The following list is presented as an example of key equipment and supplies likely required to perform vapor-phase Hg monitoring using a sorbent trap monitoring system. It is recognized that additional equipment and supplies may be needed. Collection of paired samples is required. Also required are a certified stack gas volumetric flow monitor that meets the requirements of § 75.10 and an acceptable means of correcting for the stack gas moisture content, i.e., either by using data from a certified continuous moisture monitoring system or by using an approved default moisture value (see §§ 75.11(b) and 75.12(b)).

5.1 Sorbent Trap Monitoring System

App. K § 5.1

A typical sorbent trap monitoring system is shown in Figure K–1. The monitoring system shall include the following components:

App. K § 5.1.1

5.1.1 Sorbent Traps

The sorbent media used to collect Hg must be configured in a trap with three distinct and identical segments or sections, connected in series, that are amenable to separate analyses. Section 1 is designated for primary capture of gaseous Hg. Section 2 is designated as a backup section for determination of vapor-phase Hg breakthrough. Section 3 is designated for QA/QC purposes where this section shall be spiked with an known amount of gaseous Hg^0 prior to sampling and later analyzed to determine recovery efficiency. The sorbent media may be any collection material (e.g., carbon, chemically-treated filter, etc.) capable of quantitatively capturing and recovering for subsequent analysis, all gaseous forms of Hg for the intended application. Selection of the sorbent media shall be based on the material's ability to achieve the performance criteria contained in Section 8 of this appendix as well as the sorbent's vaporphase Hg capture efficiency for the emissions matrix and the expected sampling duration at the test site. The sorbent media must be obtained from a source that can demonstrate the quality assurance and control necessary to ensure consistent reliability. The paired sorbent traps are supported on a probe (or probes) and inserted directly into the flue gas stream.

App. K § 5.1.2

5.1.2 Sampling Probe Assembly

Each probe assembly shall have a leak-free attachment to the sorbent trap(s). Each sorbent trap must be mounted at the entrance of or within the probe such that the gas sampled enters the trap directly. Each probe/sorbent trap assembly must be heated to a temperature sufficient to prevent liquid condensation in the sorbent trap(s). Auxiliary heating is required only where the stack temperature is too low to prevent condensation. Use a calibrated thermocouple to monitor the stack temperature. A single probe capable of operating the paired sorbent traps may be used. Alternatively, individual probe/sorbent trap assemblies may be used, provided that the individual sorbent traps are co-located to ensure representative Hg monitoring and are sufficiently separated to prevent aerodynamic interference.

App. K § 5.1.3

5.1.3 Moisture Removal Device

A robust moisture removal device or system, suitable for continuous duty (such as a Peltier cooler), shall be used to remove water vapor from the gas stream prior to entering the dry gas meter.

App. K § 5.1.4

5.1.4 Vacuum Pump

Use a leak-tight, vacuum pump capable of operating within the candidate's system's flow range.

App. K § 5.1.5

5.1.5 Dry Gas Meter

A dry gas meter shall be used to determine total sample volume. The meter must be sufficiently accurate to measure the total sample volume within 2 percent, must be calibrated at the selected

flow rate and conditions actually encountered during sampling, and shall be equipped with a temperature sensor capable of measuring typical meter temperatures accurately to within 3 °C for correcting final sample volume.

App. K § 5.1.6 5.1.6 Sample Flow Rate Meter and Controller

Use a flow rate indicator and controller for maintaining necessary sampling flow rates.

App. K § 5.1.7 5.1.7 Temperature Sensor

Same as Section 6.1.1.7 of Method 5 in appendix A-3 to part 60 of this chapter.

App. K § 5.1.8 5.1.8 Barometer

Same as Section 6.1.2 of Method 5 in appendix A-3 to part 60 of this chapter.

App. K § 5.1.9 5.1.9 Data Logger (Optional)

Device for recording associated and necessary ancillary information (e.g., temperatures, pressures, flow, time, etc.).

App. K § 5.2 *5.2 Gaseous Hg^o Sorbent Trap Spiking System*

A known mass of gaseous Hg^0 must be spiked onto section 3 of each sorbent trap prior to sampling. Any approach capable of quantitatively delivering known masses of Hg^0 onto sorbent traps is acceptable. Several technologies or devices are available to meet this objective. Their practicality is a function of Hg mass spike levels. For low levels, NISTcertified or NIST-traceable gas generators or tanks may be suitable, but will likely require long preparation times. A more practical, alternative system, capable of delivering almost any mass required, makes use of NIST-certified or NIST-traceable Hg salt solutions (e.g., $Hg(NO_3)_2$). With this system, an aliquot of known volume and concentration is added to a reaction vessel containing a reducing agent (e.g., stannous chloride); the Hg salt solution is reduced to Hg^0 and purged onto section 3 of the sorbent trap using an impinger sparging system.

App. K § 5.3 *5.3 Sample Analysis Equipment*

Any analytical system capable of quantitatively recovering and quantifying total gaseous Hg from sorbent media is acceptable provided that the analysis can meet the performance criteria in Section 8 of this procedure. Candidate recovery techniques include leaching, digestion, and thermal desorption. Candidate analytical techniques include ultraviolet atomic fluorescence (UV AF); ultraviolet atomic absorption (UV AA), with and without gold trapping; and in situ X-ray fluorescence (XRF) analysis.

App. K § 6 6. Reagents and Standards

Only NIST-certified or NIST-traceable calibration gas standards and reagents shall be used for the tests and procedures required under this appendix.

App. K § 7 7. Sample Collection and Transport

App. K § 7.1 *7.1 Pre-Test Procedures*

App. K § 7.1.1 7.1.1 Selection of Sampling Site

Sampling site information should be obtained in accordance with Method 1 in appendix A–1 to part 60 of this chapter. Identify a monitoring location representative of source Hg emissions. Locations shown to be free of stratification through measurement traverses for gases such as SO_2 and NO_X may be one such approach. An estimation of the expected stack Hg

concentration is required to establish a target sample flow rate, total gas sample volume, and the mass of Hg^0 to be spiked onto section 3 of each sorbent trap.

App. K § 7.1.2 7.1.2 Pre-sampling Spiking of Sorbent Traps

Based on the estimated Hg concentration in the stack, the target sample rate and the target sampling duration, calculate the expected mass loading for section 1 of each sorbent trap (for an example calculation, see section 11.1 of this appendix). The pre-sampling spike to be added to section 3 of each sorbent trap shall be within ± 50 percent of the expected section 1 mass loading. Spike section 3 of each sorbent trap at this level, as described in section 5.2 of this appendix. For each sorbent trap, keep an official record of the mass of Hg0 added to section 3. This record shall include, at a minimum, the ID number of the trap, the date and time of the spike, the name of the analyst performing the procedure, the mass of Hg0 added to section 3 of the trap (µg), and the supporting calculations. This record shall be maintained in a format suitable for inspection and audit and shall be made available to the regulatory agencies upon request.

App. K § 7.1.3 7.1.3 Pre-test Leak Check

Perform a leak check with the sorbent traps in place. Draw a vacuum in each sample train. Adjust the vacuum in the sample train to ~15? Hg. Using the dry gas meter, determine leak rate. The leakage rate must not exceed 4 percent of the target sampling rate. Once the leak check passes this criterion, carefully release the vacuum in the sample train then seal the sorbent trap inlet until the probe is ready for insertion into the stack or duct.

App. K § 7.1.4 7.1.4 Determination of Flue Gas Characteristics

Determine or measure the flue gas measurement environment characteristics (gas temperature, static pressure, gas velocity, stack moisture, etc.) in order to determine ancillary requirements such as probe heating requirements (if any), initial sample rate, proportional sampling conditions, moisture management, etc.

App. K § 7.2 *7.2 Sample Collection*

App. K § 7.2.1 7.2.1 Remove the plug from the end of each sorbent trap and store each plug in a clean sorbent trap storage container. Remove the stack or duct port cap and insert the probe(s). Secure the probe(s) and ensure that no leakage occurs between the duct and environment.

App. K § 7.2.2 7.2.2 Record initial data including the sorbent trap ID, start time, starting dry gas meter readings, initial temperatures, setpoints, and any other appropriate information.

App. K § 7.2.3 7.2.3 Flow Rate Control

Set the initial sample flow rate at the target value from section 7.1.1 of this appendix. Record the initial dry gas meter reading, stack temperature, meter temperatures, etc. Then, for every operating hour during the sampling period, record the date and time, the sample flow rate, the gas meter reading, the stack temperature, the flow meter temperatures, temperatures of heated equipment such as the vacuum lines and the probes (if heated), and the sampling system vacuum readings. Also record the stack gas flow rate, as measured by the certified flow monitor, and the ratio of the stack gas flow rate to the sample flow rate. Adjust the sampling flow rate to maintain proportional sampling, i.e., keep the ratio of the stack gas flow rate to sample flow rate constant, to within ±25 percent of the reference ratio from the first hour of the data collection period (see section 11 of this appendix). The sample flow rate through a sorbent trap monitoring system during any hour (or portion of an hour) in which the unit is not operating shall be zero.

App. K § 7.2.4

7.2.4 Stack Gas Moisture Determination

Determine stack gas moisture using a continuous moisture monitoring system, as described in § 75.11(b) or § 75.12(b). Alternatively, the owner or operator may use the appropriate fuel-specific moisture default value provided in § 75.11 or § 75.12, or a sitespecific moisture default value approved by petition under § 75.66.

App. K § 7.2.5

7.2.5 Essential Operating Data

Obtain and record any essential operating data for the facility during the test period, e.g., the barometric pressure must be obtained for correcting sample volume to standard conditions. At the end of the data collection period, record the final dry gas meter reading and the final values of all other essential parameters.

App. K § 7.2.6

7.2.6 Post Test Leak Check

When sampling is completed, turn off the sample pump, remove the probe/sorbent trap from the port and carefully re-plug the end of each sorbent trap. Perform a leak check with the sorbent traps in place, at the maximum vacuum reached during the sampling period. Use the same general approach described in section 7.1.3 of this appendix. Record the leakage rate and vacuum. The leakage rate must not exceed 4 percent of the average sampling rate for the data collection period. Following the leak check, carefully release the vacuum in the sample train.

App. K § 7.2.7

7.2.7 Sample Recovery

Recover each sampled sorbent trap by removing it from the probe, sealing both ends. Wipe any deposited material from the outside of the sorbent trap. Place the sorbent trap into an appropriate sample storage container and store/preserve in appropriate manner.

App. K § 7.2.8

7.2.8 Sample Preservation, Storage, and Transport

While the performance criteria of this approach provide for verification of appropriate sample handling, it is still important that the user consider, determine, and plan for suitable sample preservation, storage, transport, and holding times for these measurements. Therefore, procedures in ASTM D6911–03 ‘‘Standard Guide for Packaging and Shipping Environmental Samples for Laboratory Analysis’’ (incorporated by reference, see § 75.6) shall be followed for all samples.

App. K § 7.2.9

7.2.9 Sample Custody

Proper procedures and documentation for sample chain of custody are critical to ensuring data integrity. The chain of custody procedures in ASTM D4840–99 (reapproved 2004) ‘‘Standard Guide for Sample Chain-of- Custody Procedures’’ (incorporated by reference, see §75.6) shall be followed for all samples (including field samples and blanks).

App. K § 8

8. Quality Assurance and Quality Control

Table K–1 summarizes the QA/QC performance criteria that are used to validate the Hg emissions data from sorbent trap monitoring systems, including the relative accuracy test audit (RATA) requirement (see § 75.20(c)(9), section 6.5.7 of appendix A to this part, and section 2.3 of appendix B to this part). Except as provided in § 75.15(h) and as otherwise indicated in Table K–1, failure to achieve these performance criteria will result in invalidation of Hg emissions data.

TABLE K-1.-QUALITY ASSURANCE/QUALITY CONTROL CRITERIA FOR SORBENT TRAP MONITORING SYSTEMS

QA/QC test or specification	Acceptance Criteria	Frequency	Consequences if not met
Pre-test leak check	≤4% of target sampling rate	Prior to sampling	Sampling shall not commence until the lead check is passed
Post-test leak check	≤4% of average sampling rate	After sampling	Sample invalidated. **
Ratio of stack gas flow rate to sample flow rate.	Maintain within ± 25% of initial ratio from first hour of data collection period.	Every hour throughout data collection period.	~~Case-by-case evaluation.~~Sample invalidated if more that 5% of the hourly ratios or 5 hourly ratios (whichever is less restrictive) are not maintained within the acceptance criteria **
Sorbent trap section 2 break-through.	≤5% of Section 1 Hg mass	Every sample	Sample invalidated.**
Paired sorbent trap agreement	≤10% Relative Deviation (RD) if the average concentration is > 1.0 $\mu g/m^3$, and ≤ 20% RD if the average concentration is ≤ 1.0 $\mu g/m^3$.	Every sample	~~Sample invalidated. **~~Either invalidate the data from the paired traps or report the results from the trap resulting in the higher Hg concentration.
Spike Recovery Study	Average recovery between 85% and 115% for each of the 3 spike concentration levels.	Prior to analyzing field samples and prior to use of new sorbent media.	Field samples shall not be analyzed until the percent recovery criteria has been met.
Multipoint analyzer calibration	Each analyzer reading within ± 10% of true value and $r^2 \geq 0.99$.	On the day of analysis, before analyzing any samples.	Recalibrate until successful.
Analysis of independent calibration standard.	Within ± 10% of true value	Following daily calibration, prior to analyzing field samples.	Recalibrate and repeat independent standard analysis until successful.
Spike recovery from section 3 of sorbent trap.	75-125% of spike amount	Every sample	Sample invalidated.**
RATA	RA ≤ 20.0% *or* Mean difference ≤ 1.0 μg/dscm for low emitters.	For initial certification and annually thereafter.	Data from the system are invalidated until a RATA is passed.
Dry gas meter calibration (At 3 orifice initially, and 1 setting thereafter).	Calibration factor (Y) within ± 5% of average value from the initial (3-point) calibration.	Prior to initial use and at least quarterly thereafter.	Recalibrate the meter at three orifice settings to determine a new value of Y.
Temperature sensor calibration	Absolute temperature measured by sensor within ± 1.5% of a reference sensor.	Prior to initial use and at least quarterly thereafter.	Recalibrate. Sensor may not be used until specification is met.
Barometer calibration	Absolute pressure measured by instrument within ± 10 mm Hg of reading with a mercury barometer.	Prior to initial use and as least quarterly thereafter.	Recalibrate. Instrument may not be used until specification is met.

~~And data from the pair of sorbent traps are also invalidated~~** However, if only one of the paired samples fails to meet this specification and the other sample meets all of the applicable QA criteria, the results of the valid sample may be used for reporting under this part, provided that the measured Hg concentration is multiplied by a factor of 1.222. If both samples samples are invalidated and quality-assured data from a certified backup monitoring system, reference method or approved alternative monitoring system are unavailable,, substitute data must be used.

App. K § 9 **9. Calibration and Standardization**

App. K § 9.1 *9.1* Only NIST certified and NIST-traceable calibration standards (i.e., calibration gases, solutions, etc.) shall be used for the spiking and analytical procedures in this appendix.

App. K § 9.2 *9.2 Dry Gas Meter Calibration.*

Prior to its initial use, perform a full calibration of the metering system at three orifice settings to determine the average dry gas meter coefficient (Y), as described in section 10.3.1 of Method 5 in appendix A–3 to part 60 of this chapter. Thereafter, recalibrate the metering system quarterly at one intermediate orifice setting, as described in section 10.3.2 of Method 5 in appendix A–3 to part 60 of this chapter. If a quarterly recalibration shows that the value of Y has changed by more than 5 percent, repeat the full calibration of the metering system to determine a new value of Y.

App. K § 9.3 *9.3 Thermocouples and Other Temperature Sensors.*

Use the procedures and criteria in Section 10.3 of Method 2 in appendix A–1 to part 60 of this chapter to calibrate in-stack temperature sensors and thermocouples. Dial thermometers shall be calibrated against mercury-in-glass thermometers. Calibrations must be performed prior to initial use and at least quarterly thereafter. At each calibration point, the absolute temperature measured by the temperature sensor must agree to within ±1.5 percent of the temperature measured with the reference sensor, otherwise the sensor may not continue to be used.

App. K § 9.4 *9.4 Barometer.*

Calibrate against a mercury barometer. Calibration must be performed prior to initial use and at least quarterly thereafter. At each calibration point, the absolute pressure measured by the barometer must agree to within ±10 mm Hg of the pressure measured by the mercury barometer, otherwise the barometer may not continue to be used.

App. K § 9.5 *9.5 Other Sensors and Gauges.*

Calibrate all other sensors and gauges according to the procedures specified by the instrument manufacturer(s).

App. K § 9.6 *9.6 Analytical System Calibration.*

See section 10.1 of this appendix.

App. K § 10 **10. Analytical Procedures**

The analysis of the Hg samples may be conducted using any instrument or technology capable of quantifying total Hg from the sorbent media and meeting the performance criteria in section 8 of this appendix.

App. K § 10.1 *10.1 Analyzer System Calibration.*

Perform a multipoint calibration of the analyzer at three or more upscale points over the desired quantitative range (multiple calibration ranges shall be calibrated, if necessary). The field samples analyzed must fall within a calibrated, quantitative range and meet the necessary performance criteria. For samples that are suitable for aliquotting, a series of dilutions may be needed to ensure that the samples fall within a calibrated range. However, for sorbent media samples that are consumed during analysis (*e.g.*, thermal desorption techniques), extra care must be taken to ensure that the analytical system is appropriately calibrated prior to sample analysis. The calibration curve range(s) should be determined based on the anticipated level of Hg mass on the sorbent media. Knowledge of estimated stack Hg concentrations and total sample volume may be required prior to analysis. The calibration curve for use with the various analytical techniques

(*e.g.,* UV AA, UV AF, and XRF) can be generated by directly introducing standard solutions into the analyzer or by spiking the standards onto the sorbent media and then introducing into the analyzer after preparing the sorbent/standard according to the particular analytical technique. For each calibration curve, the value of the square of the linear correlation coefficient, *i.e.,* r^2, must be ≥ 0.99, and the analyzer response must be within ±10 percent of reference value at each upscale calibration point. Calibrations must be performed on the day of the analysis, before analyzing any of the samples. Following calibration, an independently prepared standard (not from same calibration stock solution) shall be analyzed. The measured value of the independently prepared standard must be within ±10 percent of the expected value.

App. K § 10.2 *10.2 Sample Preparation.*

Carefully separate the three sections of each sorbent trap. Combine for analysis all materials associated with each section, *i.e.,* any supporting substrate that the sample gas passes through prior to entering a media section (*e.g.,* glass wool, polyurethane foam, etc.) must be analyzed with that segment.

App. K § 10.3 *10.3 Spike Recovery Study.*

Before analyzing any field samples, the laboratory must demonstrate the ability to recover and quantify Hg from the sorbent media by performing the following spike recovery study for sorbent media traps spiked with elemental mercury.
Using the procedures described in sections 5.2 and 11.1 of this appendix, spike the third section of nine sorbent traps with gaseous Hg^0, *i.e.,* three traps at each of three different mass loadings, representing the range of masses anticipated in the field samples. This will yield a 3 x 3 sample matrix. Prepare and analyze the third section of each spiked trap, using the techniques that will be used to prepare and analyze the field samples. The average recovery for each spike concentration must be between 85 and 115 percent. If multiple types of sorbent media are to be analyzed, a separate spike recovery study is required for each sorbent material. If multiple ranges are calibrated, a separate spike recovery study is required for each range.

App. K § 10.4 *10.4 Field Sample Analyses.*

Analyze the sorbent trap samples following the same procedures that were used for conducting the spike recovery study. The three sections of the sorbent trap must be analyzed separately (*i.e.,* section 1, then section 2, then section 3). Quantify the mass of total Hg for each section based on analytical system response and the calibration curve from section 10.1 of this appendix. Determine the spike recovery from sorbent trap section 3. Pre-sampling spike recoveries must be between 75 and 125 percent. To report final Hg mass, normalize the data for sections 1 and 2 based on the sample-specific spike recovery, and add the normalized masses together.

App. K § 11 **11. Calculations and Data Analysis**

App. K § 11.1 *11.1 Calculation of Pre-Sampling Spiking Level.*

Determine sorbent trap section 3 spiking level using estimates of the stack Hg concentration, the target sample flow rate, and the expected sample duration. First, calculate the expected Hg mass that will be collected in section 1 of the trap. The pre-sampling spike must be within ±50 percent of this mass. Example calculation: For an estimated stack Hg concentration of 5 $\mu g/m^3$, a target sample rate of 0.30 L/min, and a sample duration of 5 days:
$(0.30\ L/min)\ (1440\ min/day)\ (5\ days)\ (10^{-3}\ m^3/liter)\ (5\mu g/m^3) = 10.8\ \mu g$
A pre-sampling spike of 10.8 μg ±50 percent is, therefore, appropriate.

App. K § 11.2 *11.2 Calculations for Flow-Proportional Sampling.*

For the first hour of the data collection period, determine the reference ratio of the stack gas volumetric flow rate to the sample flow rate, as follows:

$$R_{ref} = \frac{KQ_{ref}}{F_{ref}}$$

(Eq. K-1)
Where:
R_{ref} = Reference ratio of hourly stack gas flow rate to hourly sample flow rate
Q_{ref} = Average stack gas volumetric flow rate for first hour of collection period, adjusted for bias, if necessary, according to section 7.6.5 of appendix A to this part, (scfh)
F_{ref} = Average sample flow rate for first hour of the collection period, in appropriate units (*e.g.*, liters/min, cc/min, dscm/min)
K = Power of ten multiplier, to keep the value of R_{ref} between 1 and 100. The appropriate K value will depend on the selected units of measure for the sample flow rate.
Then, for each subsequent hour of the data collection period, calculate ratio of the stack gas flow rate to the sample flow rate using the equation K–2:

$$R_h = \frac{KQ_h}{F_h}$$

(Eq. K-2)
Where:
R_h = Ratio of hourly stack gas flow rate to hourly sample flow rate
Q_h = Average stack gas volumetric flow rate for the hour, adjusted for bias, if necessary, according to section 7.6.5 of appendix A to this part, (scfh)
F_h = Average sample flow rate for the hour, in appropriate units (*e.g.*, liters/min, cc/min, dscm/min)
K = Power of ten multiplier, to keep the value of R_h between 1 and 100. The appropriate K value will depend on the selected units of measure for the sample flow rate and the range of expected stack gas flow rates.
Maintain the value of R_h within ±25 percent of R_{ref} throughout the data collection period.

App. K § 11.3 *11.3 Calculation of Spike Recovery.*

Calculate the percent recovery of each section 3 spike, as follows:

$$\%R = \frac{M_3}{M_s} \times 100$$

(Eq. K-3)
Where:
%R = Percentage recovery of the pre-sampling spike
M_3 = Mass of Hg recovered from section 3 of the sorbent trap, (μg)
M_s = Calculated Hg mass of the pre-sampling spike, from section 7.1.2 of this appendix, (μg)

App. K § 11.4 *11.4 Calculation of Breakthrough.*

Calculate the percent breakthrough to the second section of the sorbent trap, as follows:

$$\%B = \frac{M_2}{M_1} \times 100$$

Eq. K-4)
Where:
%B = Percent breakthrough
M_2 = Mass of Hg recovered from section 2 of the sorbent trap, (µg)
M_1 = Mass of Hg recovered from section 1 of the sorbent trap, (µg)

App. K § 11.5 *11.5 Normalizing Measured Hg Mass for Section 3 Spike Recoveries.*

Based on the results of the spike recovery in section 12.3 of this appendix, normalize the Hg mass collected in sections 1 and 2 of the sorbent trap, as follows:

$$M^* = \frac{(M_1 + M_2) M_s}{M_3}$$

(Eq. K-5)
Where:
M* = Normalized total mass of Hg recovered from sections 1 and 2 of the sorbent trap, (µg)
M_1 = Mass of Hg recovered from section 1 of the sorbent trap, unadjusted, (µg)
M_2 = Mass of Hg recovered from section 2 of the sorbent trap, unadjusted, (µg)
M_s = Calculated Hg mass of the pre-sampling spike, from section 7.1.2 of this appendix, (µg)
M_3 = Mass of Hg recovered from section 3 of the sorbent trap, (µg)

App. K § 11.6 *11.6 Calculation of Hg Concentration.*

Calculate the Hg concentration for each sorbent trap, using the following equation:

$$C = \frac{M^*}{V_t}$$

(Eq. K-6)
Where:
C = Concentration of Hg for the collection period, (µg/dscm)
M* = Normalized total mass of Hg recovered from sections 1 and 2 of the sorbent trap, (µg)
V_t = Total volume of dry gas metered during the collection period, (dscm). For the purposes of this appendix, standard temperature and pressure are defined as 20℃ and 760 mm Hg, respectively.

App. K § 11.7 *11.7 Calculation of Paired Trap Agreement.*

Calculate the relative deviation (RD) between the Hg concentrations measured with the paired sorbent traps:

$$RD = \frac{|C_a - C_b|}{C_a + C_b} \times 100$$

(Eq. K-7)
Where:

RD = Relative deviation between the Hg concentrations from traps "a" and "b" (percent)
C_a = Concentration of Hg for the collection period, for sorbent trap "a" (μg/dscm)
C_b = Concentration of Hg for the collection period, for sorbent trap "b" (μg/dscm)

App. K § 11.8

11.8 Calculation of Hg Mass Emissions.

To calculate Hg mass emissions, follow the procedures in section 9.1.2 of appendix F to this part. Use the average of the two Hg concentrations from the paired traps in the calculations, except as provided in §75.15(h).

App. K § 12

12. Method Performance

These monitoring criteria and procedures have been applied to coal-fired utility boilers (including units with post-combustion emission controls), having vapor-phase Hg concentrations ranging from 0.03 μg/dscm to 100 μg/dscm.