SECTION 15
MISSING DATA PROCEDURES

Question 15.1

Topic: Number of Data Points for a Valid Hour

Question: If a CEM component collected ten averages (data sampled once per second) at six-minute intervals during the hour and only eight or nine six-minute averages were valid, would the hour's data still be valid (see § 75.10(d)(1))?

Answer: In order for the hourly average monitoring value to be considered valid during periods other than calibration, maintenance, or quality assurance, the hourly average must be calculated from a minimum of one data point collected in each of four successive 15-minute periods (minimum of four data points per hour). Therefore, if each of the four successive 15-minute periods are accounted for with the eight or nine valid readings in the example above, the hourly average calculated from the readings would be considered valid.

References: § 75.10(d)

Key Words: Data validity, Missing data

History: First published in Original March 1993 Policy Manual

Question 15.2 REVISED

Topic: Certification Test Failure

Question: If a CEM system does not pass certification tests, or does not pass a RATA, will all of the data since the last acceptable test be considered bad or missing? Will adjustments to the data be allowed to make it acceptable?

Answer: In order for data from a monitor to be considered valid, a monitoring system must be certified in accordance with the provisions in § 75.20. If a CEM system does not pass the certification tests or the Administrator issues a notice of disapproval of the certification within the 120-day review period, the data collected are invalid, and the owner or operator must follow the loss of certification procedures in § 75.20(a)(5) for all data retrospectively.

Except as discussed in the next paragraph below, once the monitoring system is certified, data are considered valid until a recertification test, RATA, quarterly linearity check or daily calibration drift check is failed. A certified monitoring system that fails a quality assurance test is deemed out-of-control until the monitoring system subsequently passes the quality assurance test. During the out-of-control period, data from the monitoring system are not valid and no adjustments to the data would be allowed. Instead the missing data provisions of § 75.30 through § 75.34 must be used to substitute valid data during the out-of-control period. A failed recertification test, RATA, or calibration drift check does not, however, invalidate data collected prior to the failed test.

In addition to the circumstances described above, EPA can issue a certification disapproval notice after the 120-day certification application review period if an audit of a system or the certification application reveals that a monitor does not meet the Part 75 performance requirements. In these circumstances, all data prospectively from the date of notice until EPA subsequently approves a certification application are considered invalid and no adjustments to the data would be allowed. Instead, the owner or operator must follow the loss of certification procedures in § 75.20(a)(5). Those procedures require the owner or operator to use maximum potential velocity (for flow), maximum potential concentration (for SO_2 and NO_x concentration), and NO_x maximum emission rate (for NO_x emission rate) values to calculate and report emissions (or flow rates) until the system is certified. (Where a diluent monitor is involved, either the minimum O_2 or maximum CO_2 concentration would be used, as applicable.)

References: § 75.24

Key Words: Missing data, Quality assurance, RATAs

History: First published in Original March 1993 Policy Manual; revised in October 1999 Revised Manual

Question 15.3

Topic: DAHS Failure

Question: In case the DAHS fails, can data captured on a data logger be used to supply missing data if the CEM system is otherwise functional?

Answer: Since the DAHS must "provide a continuous permanent record" of all measurements and required information, if a source has a device capable of collecting and storing data when the data acquisition system is not functioning properly, then the source has met the intent of the final Part 75 rule. If the analyzer is meeting performance specifications, the data can be stored in this device and the calculations performed later. Missing data procedures are not required in this circumstance. However, any equipment used as a backup data logger should be identified as a component of the DAHS by the monitoring plan. In addition, the backup device must store the data within the confines of the DAHS. Also a strip chart recorder may not be used for this purpose because the graph produced by the strip chart would require interpretation of data and would not provide the equivalent accuracy that is required.

References: § 75.10(a)

Key Words: DAHS, Missing data, Monitoring plan

History: First published in Original March 1993 Policy Manual

Question 15.4 REVISED

Topic: CO_2 Missing Data

Question: What missing data procedures apply, if any, for the CO_2 emission calculations?

Answer: Perform missing data substitution for CO_2 concentration for any unit operating hour for which there are no available quality-assured CO_2 concentration data from the CO_2 pollutant concentration monitor. Use the missing data procedures in § 75.35. Section 75.35(b) requires that until a unit has accumulated 720 quality-assured monitor operating hours of CO_2 data, the same initial missing data procedures as for SO_2 concentration are to be used (see § 75.31(b)).

When 720 quality-assured hours of CO_2 data have been accumulated, the missing data procedures found in either § 75.35(c) or (d), as appropriate, are to be used. The procedures in § 75.35(c) are in effect only until April 1, 2000. The procedures in § 75.35(d) are optional prior to April 1, 2000, but on and after April 1, 2000, the procedures in § 75.35(d) must be used.

The procedures in § 75.35(c) require substitution of the average of the CO_2 concentrations from the hour before and the hour after the missing data period, in most cases. However, if either:
(1) the percent monitor data availability as of the end of the previous unit operating quarter is < 90.0%; or (2) a CO_2 missing data period extends for more than 72 consecutive hours, then Appendix G fuel sampling is required to provide substitute data.

The new missing data procedures for CO_2 in § 75.35(d) use a mathematical algorithm modeled after the standard SO_2 missing data procedures in § 75.33. Depending on the percent data availability and the length of the missing data period, the DAHS must automatically substitute the appropriate CO_2 substitute concentration value.

References: § 75.31, § 75.33, § 75.35

Key Words: CO_2 monitoring, Missing data

History: First published in Original March 1993 Policy Manual; revised July 1995, Update #6; revised in October 1999 Revised Manual

Question 15.5

Topic: Missing Data -- Monitor Data Availability

Question: For a block of missing data, is the monitor data availability calculated by the DAHS for the first hour in which the monitor resumes operation used as the trigger for performing each data substitution under the missing data routine?

Answer: Yes. Use this one monitor data availability as the trigger for each of the hours contained in the block of missing data.

References: §§ 75.31 - 75.33

Key Words: Missing data

History: First published in May 1993, Update #1

Question 15.6

Topic: Missing Data Substitution

Question: For a block of missing flow or NO_x data, should the highest load bin recorded be used as the trigger for performing each data substitution under the missing data routine?

Answer: No. Use the monitor data availability calculated by the DAHS for the first hour in which the monitor resumes operation as the trigger for each hour in the missing data block, but then select each data substitution from the load bin corresponding to the unit load recorded for that particular hour of missing data.

References: §§ 75.31 - 75.33

Key Words: Missing data

History: First published in May 1993, Update #1

Question 15.7

Topic: Missing Data -- Unit Down Time

Question: How should the missing data algorithm handle the situation of a unit going down during a missing data period?

Answer: Do not include the hours when the unit is not operating as part of CEMS downtime or availability.

Given the following example: During a 24 hour period, the CEMS is down from hour 4 until hour 19. Meanwhile, the unit is down from hour 7 until hour 14. The HB value = 450 and the HA value = 500.

```
                            |<----------------  CEMS down  --------------->     |
HB=450ppm                   |                                                   |       HA=500ppm
                            |             |<---- Unit down ----->|              |
                     |---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
                   0       2       4       6       8      10      12      14      16      18      20      22
                                                      Hour
```

Length of CEMS outage = [19-4] - [14-7] = 8 hours = [CEMS down time] - [Unit down time]

Assuming the CEMS is an SO_2 monitor with availability $\geq$ 90%, use (HB + HA)/2 = (450+500)/2 = 475 ppm to fill in gaps from hours 4 to 7 and hours 14 to 19. For data availability, use an outage duration of 8 hours.

References: § 72.2, § 75.33

Key Words: Missing data

History: First published in November 1993, Update #2

Question 15.8

Topic: Initial Missing Data Procedure

Question: When using the initial missing data procedures for NO_x, if data in a load range do not exist and you need to go to the next higher load range, what determination code should be recorded? Code 07 for initial missing data procedures, or Code 11 for average in a corresponding load range?

Answer: Use Code 07. This is the correct code to indicate that missing NO_x emission values are substituted during the initial missing data period.

References: § 75.31; § 75.57, Table 4A

Key Words: Missing data, Reporting

History: First published in November 1993, Update #2

Question 15.9 REVISED

Topic: Appendix D Missing Data Procedures

Question: What are the missing data requirements for an Appendix D unit? What should I submit with my certification application for DAHS verification?

Answer: Revisions to Part 75, which were published on May 26, 1999, contain clarifications and other changes to the missing data and data reporting requirements for Appendix D units. No substantive changes were made to the load-based missing data procedures for missing fuel flowmeter data in Section 2.4 of Appendix D. However, for missing sulfur content, GCV, and density data, the May 26, 1999 revisions significantly changed the missing data substitution procedures. Revised Section 2.4.1 of Appendix D specifies that maximum potential values are to be used for missing sulfur content, GCV, and density data. The maximum potential values are listed in Table D-6 of Appendix D. See Question 15.17 for a discussion of how to report these new missing data requirements for sulfur content, density, and GCV under both EDR v1.3 and EDR v2.1.

Question 15.12 discusses the appropriate DAHS verification procedures for Appendix D units.

References: Appendix D, Section 2.4

Key Words: Excepted methods, Missing data, SO_2 monitoring

History: First published in November 1994, Update #4; revised July 1995, Update #6; revised in October 1999 Revised Manual

Question 15.10 REVISED

Topic: CO_2 Mass Emissions Missing Data Procedures

Question: If I use Appendix G as the method of determining CO_2 mass emissions, what do I report in RT 331 if CO_2 mass emissions are missing for a day?

Answer: If a utility uses Equations G-1 or G-2 in Appendix G to report daily CO_2 mass emissions and a value is not available for a day, use the missing data procedures in Section 5 of Appendix G to substitute for missing carbon content or GCV data, and then apply the appropriate CO_2 mass emission equation.

References: Appendix G, Section 5

Key Words: CO_2 monitoring, Electronic report formats, Excepted methods, Missing data, Reporting

History: First published in November 1994, Update #4; revised in October 1999 Revised Manual

Question 15.11 RETIRED

Question 15.12 REVISED

Topic: Appendix D and E Missing Data Procedures

Question: Does EPA intend to release a version of DCAS for Appendix D and E? If not, what should I do to certify my Appendix D and E DAHS software?

Answer: The EPA does not intend to release a version of DCAS for Appendices D and E. The EPA still expects utilities to demonstrate that their DAHS correctly substitutes missing data according to the requirements of Part 75.

The documentation for demonstrating correct missing data substitution should include:

(1) A list of all of the tests that were performed. Include dates, times and results. The EPA recommends that, for EDR v2.1, you use the format in the Appendix D and E Missing Data Verification Checklist, which is included immediately after this answer. Regardless of whether the format in the checklist is used, all of the tests listed in the checklist are required.

(2) A signed certification statement that reads as follows:

> I certify that the automated Data Acquisition and Handling System (DAHS) component of each CEM system identified here was tested and that proper computation of the missing data substitution procedures was verified according to 40 CFR Part 75. The results of the verification tests for the missing data routine are available on-site in a format suitable for inspection, as required by 40 CFR §§ 75.20(c)(9) and 75.63(a)(2)(iii).

In addition to submitting this information, copies of the DAHS testing must be kept available on site for inspection.

References: § 75.20; § 75.63; Appendix D; Appendix E

Key Words: Excepted methods, Missing data, NO_x monitoring, SO_2 monitoring

History: First published in July 1995, Update #6; revised in March 1997, Update #11; revised in October 1999 Revised Manual

Appendix D and E Missing Data Verification Checklist

Please enter a "P" for any test that was performed and passed, an "F" for any test that was performed and failed and an "NA" for any test that is not applicable to the DAHS being tested.

Appendix D Units that burn only natural gas:	**Test Date(s) ________________________**
	(1) The DAHS substitutes average flow rate at a given load level based on the previous 720 hours of operation.
	(2) The DAHS substitutes the average value from the next available higher load range if no data is available in the corresponding load range.
	(3) The DAHS substitutes the maximum hourly fuel flow rate if no data is available at either a corresponding load range or a higher load range.
	(4) If no sulfur content or GCV is available from fuel sampling and analysis, the DAHS substitutes the maximum potential sulfur content or GCV of that fuel from Table D-6, Appendix D.
Appendix D Units that burn only oil:	**Test Date(s) ________________________**
	(1) The DAHS substitutes average flow rate at a given load level based on the previous 720 hours of operation.
	(2) The DAHS substitutes the average value from the next available higher load range if no data is available in the corresponding load range.
	(3) The DAHS substitutes the maximum hourly fuel flow rate if no data is available at either a corresponding load range or a higher load range.
	(4) If no sulfur content, GCV or, when necessary, density is available from fuel sampling and analysis the DAHS substitutes the maximum potential sulfur content, GCV, or density of that fuel from Table D-6, Appendix D.

Appendix D and E Missing Data Verification Checklist (cont.)

Please enter a "P" for any test that was performed and passed, an "F" for any test that was performed and failed and an "NA" for any test that is not applicable to the DAHS being tested.

Appendix D Units that can burn both gas and oil:	Test Date(s) ___________________
(1) If data are available in the corresponding load range:	
	(a) In an hour when only gas is burned the DAHS substitutes the average fuel flow rate at the corresponding load range from the last 720 hours of gas burning.
	(b) In an hour when only oil is burned the DAHS substitutes the average fuel flow rate at the corresponding load range from the last 720 hours of oil burning.
	(c) In an hour when both oil and gas are burned but gas fuel flow rate is missing, the DAHS substitutes the maximum fuel flow rate for gas at the corresponding load range from the last 720 hours in which multiple fuels were fired.
	(d) In an hour when both oil and gas are burned but oil fuel flow rate is missing, the DAHS substitutes the maximum fuel flow rate for oil at the corresponding load range from the last 720 hours in which multiple fuels were fired.
(2) If data are not available at the corresponding load range but are available at a higher load range:	
	(a) In an hour when only gas is burned, the DAHS substitutes the average fuel flow rate from the last 720 hours of gas burning from the next higher available load range.
	(b) In an hour when only oil is burned, the DAHS substitutes the average fuel flow rate from the last 720 hours of oil burning from the next higher available load range.
	(c) In an hour when both oil and gas are burned, but gas fuel flow rate is missing, the DAHS substitutes the maximum fuel flow rate for gas from the last 720 hours in which multiple fuels were fired from the next higher available load range.
	(d) In an hour when both oil and gas are burned, but oil fuel flow rate is missing, the DAHS substitutes the maximum fuel flow rate for oil from the last 720 hours in which multiple fuels were fired from the next higher available load range.
(3) If data are not available at the corresponding load range or a higher load range:	
	(a) For hours when only gas is burned, the DAHS substitutes the maximum potential fuel flow rate (as defined in Section 2.4.2.2 of Appendix D) for gas.
	(b) For hours when only oil is burned, the DAHS substitutes the maximum potential fuel flow rate (as defined in Section 2.4.2.2 of Appendix D) for oil.
	(c) For hours when oil and gas are burned, but gas fuel flow rate is missing, the DAHS substitutes the maximum potential fuel flow rate (as defined in Section 2.4.2.2 of Appendix D) for gas.
	(d) For hours when oil and gas are burned, but oil fuel flow rate is missing, the DAHS substitutes the maximum potential fuel flow rate (as defined in Section 2.4.2.2 of Appendix D) for oil.
Peaking Units:	Test Date(s) ___________________
	(1) If no fuel flow rate data are available for a fuel flow meter system installed on a peaking unit, the DAHS substitutes the maximum potential fuel flow rate (as defined in Section 2.4.2.2 of Appendix D).
For Units using Appendix E:	Test Date(s) ___________________
	(1) When the quality assurance operating parameters are not within the limits specified in the monitoring plan, the DAHS substitutes the maximum NO_x rate recorded during the last series of baseline tests.

Question 15.13 REVISED

Topic: CO_2 and Heat Input Missing Data Procedures

Question: We have the following questions concerning how to apply Appendices F and G for substituting missing CO_2 concentration and heat input data:

(1) If more than one type of fuel is fired, is it necessary to convert all fuel flows to tons?

(2) If gross calorific value (GCV) data are missing, how do we substitute?

(3) Should sampling and fuel flow entry occur whenever the fuel is burned or only when the missing data procedures are called for?

(4) What are missing data procedures for % carbon in fuel?

(5) If fuel flow is allowed to be entered from company records and the value does not get entered, what should be filled in its place?

(6) If the heat input gap ends mid-week, which weekly fuel flow should be applied, the previous or the current?

(7) When § 75.35 references Appendix G procedures, does this mean the use of Equation G-1?

Answer: The provisions in § 75.35(c) which require the use of Appendix G fuel sampling procedures during periods of missing CO_2 data from a CEMS will no longer be in effect, as of April 1, 2000. The guidance given in paragraphs (1) through (7), below, is therefore to be regarded as interim guidance that will no longer apply after April 1, 2000, and do not apply prior to April 1, 2000 if the owner or operator opts to comply early with § 75.35(d) rather than 75.35(c).

(1) If you are combusting more than one fuel, keep track of the total carbon dioxide emitted for all fuels, as indicated in Equation G-1. Equation G-1 merely calls for a total mass of carbon from all fuels. You may use any calculation method to combine information for all fuels that will yield total carbon from all fuels.

(2) If no GCV data are available from fuel sampling and analysis, the DAHS substitutes the maximum potential GCV of that fuel from Table D-6, Appendix D.

(3) Fuel carbon content, GCV, and fuel flow information are not required unless there are CO_2 missing data for outages requiring the Appendix G fuel sampling procedures. However, if the availability during the last unit operating hour during the previous calendar quarter was less than 90.0%, or

no quality-assured CO_2 concentration data are available for a period of 72 consecutive unit operating hours or more, the utility will need to do sampling and keep track of fuel flow so that they will be able to substitute any CO_2 missing data.

(4) If carbon content values are missing, use carbon content from the most recent sample for the same fuel and the same fuel oil grade or coal rank. If possible, use another sample from the same supply.

(5) Use the applicable fuel flowmeter missing data procedures in Section 2.4 of Appendix D.

(6) If the heat input gap ends mid-week, use the fuel flow for that current week.

(7) Yes. Use the procedures under Equation G-1 where § 75.35 calls for Appendix G procedures. (Gas-fired units could also use Equation G-4.)

References: § 75.35; Appendix G

Key Words: Heat input, Missing data

History: First published in November 1995, Update #7; revised in October 1999 Revised Manual

Question 15.14 REVISED

Topic: Appropriate Procedures for Infrequently Operated Units

Question: A unit operates for fewer than 720 hours in a three year period (for example, 700 hours of operation from April 1, 1997 to April 1, 2000). Does the utility continue to implement the standard missing data procedures for SO_2 or does the utility instead implement the initial missing data procedures?

Answer: Continue to use the standard missing data procedures. Once you have begun using the standard missing data procedures (i.e., when either: (1) 720 quality-assured monitor operating hours of SO_2 have been recorded since initial certification; or (2) when three years have passed since initial certification (whichever occurs first)), the standard missing data procedures must continue to be used. It makes no difference how many unit operating hours there are in any subsequent year (or, as in this example, in any three-year period). The 720-hour historical lookbacks for SO_2 missing data substitution are based on previously recorded quality-assured monitor operating hours.

References: § 75.31; § 75.32; § 75.33(a)

Key Words: Missing data

History: First published in November 1995, Update #7; revised in October 1999 Revised Manual

Question 15.15 RETIRED

Question 15.16

Topic: Retraction of ETS User Bulletin #2

Question: Does the Closure Methodology replace the missing data substitution policy in ETS User Bulletin #2?

Answer: The EPA has retracted ETS User Bulletin #2 and does not consider this official EPA policy. Some utilities had the incorrect impression that the Agency was intending to substitute reported data using the missing data substitution procedures without giving prior notice or an opportunity to resubmit a corrected report. This was never EPA's intention.

References: N/A

Key Words: Missing data

History: First published in November 1995, Update #7

Question 15.17 REVISED

Topic: Appendix D Missing Data Procedures -- GCV and Density

Question: Which sulfur content value, gross calorific value (GCV), and density value do we use for a missing oil sample? What do we report?

Answer: Use the maximum potential sulfur content, GCV, or density value for the oil from Table D-6 in Appendix D, to calculate SO_2 mass emissions. Report this GCV in column 34 of RT 302 and use a missing data flag of "1" in column 44 of RT 302 (if reporting in EDR v1.3) or a data flag of "8" in column 90 of RT 302 (if reporting in EDR v2.1). Report the maximum potential density value for that fuel from Table D-6, Appendix D in column 75 of RT 302 and use a missing data flag of "1" in column 88 of RT 302 (if reporting in EDR v1.3) or a data flag of "8" in column 92 of RT 302 (if reporting in EDR v2.1).

References: Appendix D, Section 2.4

Key Words: Electronic report formats, Excepted methods, Missing data, SO_2 monitoring

History: First published in November 1995, Update #7; revised in October 1999 Revised Manual

Question 15.18 RETIRED

Question 15.19 REVISED

Topic: Appendix E Missing Data Procedures

Question: How do we fill in missing data under Appendix E for the following situations:

! Missing fuel flow rate or gross calorific value data

! NO_x emission rate, when excess O_2 is outside the original testing limits

! Excess O_2

! NO_x emission rate, when hourly heat input is higher than the maximum heat input correlated on the curve

! NO_x emission rate, when the correlation curve is incomplete?

Also, if data are missing for excess O_2 (or other quality assurance/quality control parameters) for a given hour, is this hour considered "out-of-spec"?

Answer: For missing fuel flow rate and missing gross calorific value data, use the applicable missing data procedures in Section 2.4 of Appendix D (see Questions 15.9, 15.12, 15.17, 15.22, and 15.23).

When excess O_2 exceeds by more than 2.0 percentage points O_2 the excess O_2 value recorded at the same operating heat input rate as during the last NO_x emission rate test, substitute the highest tested NO_x emission rate on the curve for the fuel. Between heat input rate points that were actually tested, make a linear interpolation of the excess O_2. In RT 323 (if used), report a flag value of "N" in column 21 to show that the excess O_2 is outside of the specified value. If RT 324 is used, report the "N" flag in column 24. Below the lowest heat input rate point do not keep track of the excess O_2.

For missing or invalid excess O_2 data, substitute the highest NO_x emission rate on the curve for the fuel. However, in RT 323 (if used), report a flag value of "X" in column 21. If RT 324 is used, report the "X" flag in column 24. This indicates that the hour is not demonstrated to be within the specified limits in section 2.3 of Appendix E, but it also is not demonstrated to be outside the specified limits. Use of the "X" flag is optional; you may choose instead to treat these hours as out of specification. Note that hours marked with a flag of "N" count towards the 16 consecutive unit operating hours before retesting is required, while hours marked with a flag of "X" do not count for this purpose. However, in either case, the data count against the availability of data where the unit operates within the parameters. If the data availability falls below 90.0 percent, the Agency may require retesting.

Note that the same procedures apply when a quality assurance/quality control parameter other than excess O_2 is missing (e.g., steam/fuel injection ratio, compressor ratio).

If the hourly heat input is higher then the maximum heat input correlated on the curve, then calculate the maximum potential NO_x emission rate and calculate the NO_x emission rate that would result from extrapolating the last two heat input points on the correlation curve. Substitute the higher of these two values. During your next periodic or quality assurance/quality control related testing, try to test under conditions more representative of your maximum potential heat rate. If possible, use the new maximum heat input as the highest heat input point. Flag these data in RT 323 (if used) with a "W" in column 21 or, if applicable, with a "W" in column 24 of RT 324 (see EDR v2.1 Reporting Instructions).

If the NO_x versus heat input curve is not complete, then use the maximum potential NO_x emission rate and complete your testing as soon as possible. Calculate the maximum potential NO_x emission rate (MER) using the applicable equation from Appendix F to Part 75 or from EPA Method 19. In calculating the MER, use the maximum potential concentration of NO_x, and the minimum carbon dioxide concentration or maximum oxygen concentration under typical operating conditions (based on historical information). Alternatively, you may use the appropriate diluent cap value in the calculations (i.e., 5.0% CO_2 or 14.0% O_2 for boilers, or 1.0% CO_2 or 19.0% O_2 for turbines), as specified in Section 2.1.2.1 of Appendix A.

References: Appendix D, Section 2.4; Appendix E, Sections 2.3 and 2.5

Key Words: Excepted methods, Missing data, NO_x monitoring

History: First published in November 1995, Update #7; revised in October 1999 Revised Manual

Question 15.20

Topic: Missing Load Data

Question: For the new fuel flow missing data procedures, what should we do if MW is missing for an hour of missing fuel flow? Can we use maximum value substitution of fuel flow? If MW is missing for an hour of valid flow, should the quality assured flow rate be entered into the lowest load range?

Answer: If MW data are available but are not in the DAHS, these data must be entered into the DAHS manually. If the MW data are not available, you must use the unit's maximum load. In this case treat the load ranges for fuel flow missing data as you would the load ranges for NO_x and flow stack monitors. If MW are missing for an hour of missing fuel flow, substitute values from the highest load range. If MW data are missing for an hour of valid flow, enter the flow rate in the lowest load range.

References: Appendix D, Section 2.4.2

Key Words: Excepted methods, Fuel sampling, Missing data

History: First published in November 1995, Update #7

Question 15.21

Topic: Appendix D Missing Data Procedures

Question: The new missing data procedures for fuel flow during combustion of multiple fuels require substitution of the maximum flow rate in a load range, rather than the average. Why is the approach different for multiple fuels?

Answer: The approach is different for multiple fuels in order to avoid underestimation of SO_2 mass emissions. When a unit combusts two different fuels simultaneously, each with its own fuel flow meter, there is not a direct relationship between the flow rate of a single fuel and the unit load. It would be possible to underestimate SO_2 emissions significantly if a low oil flow value from an hour with combustion of a little oil and mostly natural gas were substituted for the oil flow rate during an hour when the unit actually combusted mostly oil and a little natural gas. However, substituting the maximum value in the load range during periods of co-firing ensure that the flow rate and SO_2 mass emissions will not be underestimated.

References: Appendix D, Section 2.4.2.3

Key Words: Excepted methods, Fuel sampling, Missing data

History: First published in November 1995, Update #7

Question 15.22 REVISED

Topic: Appendix D Missing Data Procedures

Question: Are there any initial missing data procedures in Appendix D for fuel flowmeter data?

Answer: No. Beginning with the hour of provisional certification, use the standard missing data procedures in Section 2.4 of Appendix D. If there are fewer than 720 hours of historical quality-assured fuel flow data available for a look back during a missing data period, use whatever quality-assured hours are available, consistent with Section 2.4.2.2 of Appendix D. See also the answer to Question 15.12.

References: Appendix D, Section 2.4

Key Words: Excepted methods, Fuel sampling, Missing data

History: First published in November 1995, Update #7; revised in October 1999 Revised Manual

Question 15.23 REVISED

Topic: Appendix D Missing Data Procedures

Question: In the missing data procedures for fuel flowmeters in Appendix D, does the 720-hour look back period include only hours in which a quality-assured fuel flow rate was recorded?

Answer: Yes. Do not include in the lookback period any hours when no fuel was combusted or any hours when the fuel flowmeter was either malfunctioning or not operating. If there are fewer than 720 hours of historical quality-assured fuel flow data for a particular fuel during a missing data period, use whatever quality-assured hours are available, consistent with Section 2.4.2.2 of Appendix D.

References: Appendix D, Section 2.4

Key Words: Excepted methods, Fuel sampling, Missing data

History: First published in November 1995, Update #7; revised in October 1999 Revised Manual

Question 15.24 REVISED

Topic: Valid Hour -- Calibration Error Tests

Question: If a successful daily calibration error test of a CEMS ended at 08:16 and the unit completes shutdown at 08:29 with at least one minute of valid data, are there sufficient data for a valid hour?

Answer: No. During periods when calibration, quality assurance, or maintenance activities pursuant to § 75.21 and Appendix B are being performed, a valid hour shall consist of at least two data points separated by a minimum of 15 minutes.

References: § 75.10, § 75.21; Appendix B

Key Words: Data validity, Missing data

History: First published in November 1995, Update #7; revised in October 1999 Revised Manual

Question 15.25 RETIRED

Question 15.26 REVISED

Topic: Missed QA/QC Tests -- Linearity Checks and RATAs

Question: A utility did not perform a required linearity test or RATA in a quarter. Must the utility immediately begin to report using substitute data in the next quarter?

Answer: No, EPA recognizes that there are times that a linearity check or RATA deadline may be missed due to circumstances beyond a utility's control. Therefore, the revisions to Part 75 published on May 26, 1999 provide a grace period in which a missed QA test may be completed without loss of data. Section 2.2.4 of Appendix B provides a 168 unit (or stack) operating hour grace period for a missed linearity check and Section 2.3.3 of Appendix B provides a 720 unit (or stack) operating hour grace period for a missed RATA. If the required QA test has not been successfully completed within the grace period, data from the monitoring system become invalid beginning with the first operating hour after the grace period expires.

References: Appendix B, Sections 2.2.4 and 2.3.3

Key Words: Deadlines, Linearity, Missing data, RATA

History: First published in March 1997, Update #11; revised in October 1999 Revised Manual

Question 15.27 RETIRED

Question 15.28

Topic: Diluent Monitor Data Availability

Question: For CO_2 and heat input missing data, when do I start reporting diluent monitor data availability on an hourly basis -- with the hour I do the EDR v2.1 upgrade?

Answer: This is covered in §§ 75.35 and 75.36. In the case where an existing, certified diluent monitor is in place, when you implement the new missing data algorithms for CO_2 or O_2 (as applicable) you must perform the initial missing data procedures of § 75.31(b) for the first 720 quality assured monitor operating hours, and then switch to the standard missing data procedures in § 75.35(d) or § 75.36(d), as applicable. Monitor data availability calculation and reporting begins when you begin using the standard missing data procedures.

The new CO_2 and heat input missing data algorithms may be implemented beginning on January 1, 2000 and must be implemented no later than April 1, 2000. The first operating hour of the quarter in which you first report data in EDR v2.1 is the proper point at which to start using the initial missing data procedures of § 75.31(b). Note that you may upgrade to EDR v2.1 only at the beginning of a calendar quarter, not in the middle of a quarter.

References: § 75.35, § 75.36

Key Words: Diluent monitors, Missing data

History: First published in March 2000, Update #12

Question 15.29

Topic: Missing Data Procedures After EDR Upgrade

Question: When I upgrade to EDR v2.1, should I reset the missing data clock and the percent monitor data availability (PMA) and begin using the initial missing data procedures in § 75.31?

Answer: It depends on the parameter. Use the initial missing data procedures of § 75.31 only for parameters such as CO_2 and moisture, for which hourly reporting of PMA was not required in the past, but now is required under the May 26, 1999 revisions to Part 75. However, for SO_2, NO_x, and flow rate, maintain the connection with the historical data streams when you switch to EDR v2.1 (i.e., do not reset the missing data lookback period or the PMA).

References: § 75.31

Key Words: Missing data

History: First published in March 2000, Update #12

Question 15.30

Topic: Valid Hours

Question: Suppose that in the first two 15-minute quadrants of an hour (Hour # 1), I collect sufficient valid CEMS data to meet the requirement of § 75.10(d)(1) and then I perform preventative maintenance on the CEMS for the remainder of that hour, extending into the next clock hour (Hour # 2). If the monitor passes a post-maintenance calibration error test in Hour # 2 and collects sufficient valid data in the last two 15 minute quadrants of Hour # 2 to satisfy § 75.10(d)(1), are both Hours # 1 and 2 valid, or is only Hour # 2 valid ?

Answer: The emission data for both Hours # 1 and # 2 may be reported as quality-assured. The principal data capture requirement for Part 75 sources in § 75.10(d)(1) states that in order to validate data for an hour, you must obtain at least one valid data point in each quadrant of the hour in which fuel is combusted. However, § 75.10(d)(1) provides an exception to this requirement for hours in which quality assurance testing and preventive maintenance activities are performed. For such hours, a minimum of two data points, separated by at least 15 minutes, are required to validate the hour.

In the present case, the emission data collected in Hour # 1 are considered valid, because the data were recorded prior to the maintenance event (i.e., prior to commencement of the out-of-control period). The data in Hour # 2 are valid because they were collected after a successful post-maintenance calibration error test (i.e., after the end of the out-of-control period).

References: § 75.10(d)(1)

Key Words: Data validity

History: First published in March 2000, Update #12

SECTION 16
SCRUBBERS/PARAMETRIC MONITORING PROCEDURES

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Question 16.1 REVISED

Topic: Missing Data -- Scrubbed Units

Question: Are the parametric monitoring procedures, used for recording and reporting during missing data periods, optional for scrubbed units?

Answer: Yes. The parametric monitoring procedures referenced in § 75.34(a)(2), (b), and (c) and described in detail in 40 CFR Part 75, Appendix C are optional. The owner or operator of a unit with add-on control devices has the following options with respect to parameter monitoring and calculating missing data.

(1) **Standard Missing Data Routines with Parametric Supporting Data**

The owner or operator may use the standard missing data routines in § 75.33 provided that the parameters specified in § 75.55(b) or § 75.58(b) (or similar parameters appropriate to the particular site for demonstrating proper emissions control) are recorded and maintained on-site, and provided that the parameter data document proper operation of the control device during the missing data period. The owner or operator does not need to report this information to EPA unless EPA requests the data. The owner or operator also does not need to use a DAHS to record the parameters. This is because the parameter data are not used to calculate the missing data, but are only used to document that the control system is operating properly. If the monitor data availability for the affected unit falls below 90%, then the owner or operator also may submit a petition as described under Option (4) below.

In order to demonstrate proper operation, the utility must determine the range of each appropriate scrubber operating parameter that corresponds to proper operation, the designated representative must submit a list of the range of these parameters as an update to the monitoring plan with the quarterly report for fourth quarter 1995, and the utility must keep records to show whether the scrubber is operating inside or outside of those ranges. In quarterly reports beginning with the report for fourth quarter 1995, the designated representative must certify that the add-on emission controls were operating within the range of parameters listed in the monitoring plan, and that the substitute values recorded during the quarter do not systematically underestimate SO_2 or NO_x emissions, pursuant to § 75.34.

(2) **No Parameter Data**

Pursuant to § 75.34(d), if the owner or operator does not have data available to demonstrate that an add-on control device is operating properly (i.e., the data specified in § 75.58(b)), the owner or operator must, as applicable: (a) use the maximum potential NO_x emission rate; or (b) use the maximum hourly SO_2 concentration recorded by the inlet monitor for the previous 720 operating hours in calculating SO_2 emissions. If no inlet SO_2 monitor concentration data exist, then the owner or operator must use the maximum potential inlet SO_2 concentration established pursuant to Section 2.1.1.1 of Appendix A to Part 75. These maximum SO_2 or NO_x values, as applicable, must be used to substitute for missing data until parametric data demonstrating proper operation of the SO_2 or NO_x controls are available. Note that these values may be higher than the maximum recorded value used to substitute values under the standard missing data procedures in § 75.33 when monitor data availability is < 90%.

(3) **Parametric Missing Data Substitution Method**

The owner or operator can petition EPA to use parametric monitoring to calculate substitute values during missing data periods. This option is referenced in § 75.34(a)(2), (b), and (c), and described in detail in Appendix C and § 75.66(e). The petition should be submitted prior to implementing a parametric substitution approach and must include the demonstration requirements in Appendix C. Once the petition is approved by EPA, the owner or operator must use an automated data acquisition and handling system to record and report the parameters specified in § 75.58(b) (and any other parameters approved during the petition process) for use in determining the substitute values used to fill in for missing CEM data. These parameters then must be recorded continuously and reported during missing data periods in the Electronic Reporting Format specified by the Administrator, as required under § 75.64.

If the monitor data availability for the affected unit falls below 90%, then the owner or operator must use either the standard missing data routines under Option (1) above or submit a separate petition as described in Option (4) below. If parameter data are not available to demonstrate that the control device is operating properly, then the owner or operator must use Option (2) above to calculate substitute values on the basis of maximum potential concentration or maximum potential NO_x emission rate.

(4) **Parameter Data Used to Support Use of Maximum Controlled Emission Rate**

When monitor data availability is < 90% the standard missing data procedures require the owner or operator to use the "maximum recorded value" in the lookback period (720 operating hours for SO_2 and 2160 operating hours for NO_x) as the substitute value for missing data. Because that value may include periods when a control device was not operating, § 75.34(a)(1) gives the owner or operator the option to petition EPA to use instead the "maximum controlled emission rate" during the previous 720 operating hour period as the substitute value for missing SO_2 or NO_x data, provided that parameter data documenting proper operation of the control device are available during the missing data period.

The required petition to EPA could be included as part of the quarterly report. The designated representative would be required to provide the following information pursuant to § 75.66(f): (a) data availability for the missing data period was < 90%; (b) parametric monitoring records (specifically, the records identified by § 75.55(b) or § 75.58(b)) demonstrating proper control device operation (within the range of operating parameters in the monitoring plan for the unit) are available on site; (c) a list of average hourly values for the last 720 operating hours, highlighting the maximum recorded value and the maximum controlled emission rate value; and (d) an explanation and information on operation of the add-on emission controls demonstrating that the selected historical SO_2 concentration or NO_x emission rate does not underestimate emissions during the missing data period. The petition must include a certified statement that items (a) and (b) are true, accurate, and complete. The actual parametric records for every hour need not be submitted, in contrast to the reporting requirements under Option (3) above where the recorded parameters are used to calculate the substitute values.

References: §75.33, § 75.34, § 75.58(b), § 75.64(c), § 75.66(e), § 75.66(f); Appendix C

Key Words: Control devices, Missing data

History: First published in May 1993, Update #1; revised July 1995, Update #6; revised in October 1999 Revised Manual

Question 16.1A **RETIRED**

Question 16.2

Topic: Missing Data -- Scrubbed Units

Question: Do all parameters for all scrubber modules need to be obtained in order for sources to demonstrate that a scrubber is working sufficiently for the regular missing data procedures to apply?

Answer: No, but there must be a sufficiently large amount of data to demonstrate that the FGD system is working at, or close to, its regular efficiency. As a guideline, EPA strongly recommends at least 90% of the data required be available during monitor outages. Without this data, the provisions of § 75.34(d) apply. (See option (2) in Question 16.1 for a discussion of § 75.34(d).)

References: § 75.34(a)(1)

Key Words: Control devices, Missing data

History: First published in May 1993, Update #1

Question 16.3 REVISED

Topic: Control Device Operation during a Missing Data Period

Question: Section 75.34(d) states that "the owner or operator shall keep records of information as described in subpart F of this part to verify the proper operation of the SO_2 or NO_x emission controls during all periods of SO_2 or NO_x emission missing data." If data substitution is being completed in accordance with § 75.34(a)(1), what specific scrubber operating information must be recorded? Also, please indicate the specific sections of subpart F which provide this information.

Answer: The specific recordkeeping procedures for the proper operation of the SO_2 and NO_x emissions controls can be found in § 75.58(b)(3). The information must be recorded but need not be reported to the Agency with the quarterly report. This recorded information must be kept at the site for 3 years. This information must be available on demand in the event of a field audit or a request by the Agency. The information to verify the proper operation of an emission control device can be recorded by strip chart or by electronic media (i.e., by computer).

References: § 75.34(d), § 75.58(b)(3), § 75.64(a)(2)(iv)

Key Words: Control devices, Missing data, Recordkeeping

History: First published in November 1993, Update #2; revised July 1995, Update #6; revised in October 1999 Revised Manual

Question 16.4

Topic: Scrubber Modules -- Slurry Flow Measurement

Question: For an FGD with several modules, can verification and reporting of the number of pumps operating on each module and the tested flow rate of the pump be used to calculate the flow rate to meet the flow measurement requirement?

Answer: Yes, the verification of flow of slurry through the pipes can be performed by reporting the number of pumps operating on each module and the tested flow rate of each pump in operation, provided that the pumps are all fixed-rate. If the pumps operate at variable rates, then there must be flowmeters for each scrubber module.

References: § 75.34; Appendix C, Section 1.2

Key Words: Control devices, Parametric procedures

History: First published in November 1993, Update #2

Question 16.5 RETIRED

Question 16.6 RETIRED

Question 16.7 RETIRED

Question 16.8 RETIRED

Question 16.9 RETIRED

Question 16.10 REVISED

Topic: Scrubber Installation -- Interim Reporting

Question: When SO_2 scrubbers are installed on Part 75 affected units, this often involves construction of a new stack and installation of new continuous emission monitoring systems. Consequently, there will, in most instances, be a period of time after the scrubber comes on-line during which the unit will emit SO_2, NO_x, and CO_2 into the atmosphere without having certified monitors to measure the emissions. Must the maximum potential concentration and velocity values be used for reporting during this time interval? If not, how should emission data be reported from a scrubbed unit in the interval prior to certification of the continuous emission monitors?

Answer: In most instances, it is not necessary to use maximum potential concentration and flow rate values. Rather, in the time interval that extends from the initial hour of unit operation following scrubber installation until the hour of successful completion of the certification tests of the continuous monitoring systems, follow the interim reporting guidelines given in Sections I and II, below.

INTERIM REPORTING GUIDELINES FOR SCRUBBED UNITS

The interim reporting guidelines in Sections I and II, below, apply only to situations in which: (1) a flue gas desulfurization (FGD) system is installed on a Part 75 affected unit (or units); and (2) both the normal operation of the affected unit(s) and the ability of the continuous emission monitoring systems to provide quality-assured SO_2 emissions data for Part 75 reporting purposes are disrupted by the installation of the FGD system. Further, the guidelines apply only for a limited time period, not to exceed 90 calendar days, beginning with the first hour of operation of the unit(s) after installation of the FGD system (see § 75.4(e)), and extending to the hour of completion of the CEM certification tests. These guidelines are not to be used under any other circumstances.

I. **CERTIFICATION TEST SEQUENCE:**

A. In cases where scrubber installation involves extensive modification of the flue gas handling system and construction of a new stack and requires the installation of new (or relocated) continuous emission monitoring systems, the recommended sequence of CEM certification tests is as follows:

(1) Install all CEM systems prior to initial scrubber operation. Prepare the monitors for use in accordance with the manufacturer's instructions.

(2) Update the monitoring plan to reflect the changes to the process and/or monitoring systems. Assign new component and system ID numbers in RT 510 of the monitoring plan to all new and relocated monitoring systems. The DAHS component ID number need not be changed, however, if the same DAHS and the same software are used before and after scrubber installation.

(3) For the gas monitoring systems, initiate a calibration error test as soon as possible after the scrubbed unit first comes on-line. The unit must be in operation during the test, although no particular load or scrubber efficiency is required. Check the calibration of both the low and high ranges of the SO_2 monitor.

Until the monitor has passed a calibration error test, no data generated by a gas monitor will be accepted, and missing data routines as stated in § 75.31 must be applied.

(4) For each gas monitor, once a calibration error test has been passed, continue performing daily calibration error tests of the monitor on each subsequent unit operating day.

(5) For each installed flow monitor, any necessary characterization or linearization of the instrument with respect to EPA Method 2 (or its allowable alternatives) should be done as soon as possible after initial operation of the scrubbed unit. Until the pre-RATA adjustments of the monitor have been completed, no data from a flow monitor will be accepted, and missing data routines must be applied. Therefore, for missing data purposes, it is advisable to collect Reference Method 2 data while the linearization or other pre-RATA adjustments are in progress, in order to fill one or more load ranges (see Section II.C, below).

Hourly Method 2 data must be collected in accordance with the procedures outlined in Question 21.37.

(6) When linearization of the flow monitor is completed (or, if no pre-RATA adjustment procedures are considered necessary), initiate a calibration error test and interference check of the monitor, and repeat the tests on each subsequent operating day.

(7) After all set up, adjustment, linearization, etc. of a monitor is completed and a calibration error test has been passed, you may either: (a) invalidate all data from the monitor until all of the required certification tests have been passed; or (b) apply the data validation procedures and timelines of § 75.20(b)(3) to conditionally validate data from the monitor until the certification tests have been passed. If you select option (b), use the first successful calibration error test performed after the instrument set-up as the probationary calibration error test described under § 75.20(b)(3)(ii).

(8) It is recommended that the linearity checks, cycle/response time tests and the 7-day calibration error tests of the monitors be initiated first. Perform linearity checks on both the low and high SO_2 monitor ranges. The unit needs only to be operating (no particular load-level or scrubber efficiency is required) during these tests.

(9) It is recommended that RATA testing of the SO_2, NO_x, flow rate, and CO_2 monitoring systems be done last in the test sequence, commencing as soon as stable unit and scrubber operation at normal load is attained.

(10) To facilitate data validation and reporting, initiate and complete the entire certification test sequence within the same calendar quarter, if at all possible.

(11) The certification tests of all monitoring systems must be completed no later than 90 days after effluent gases from the scrubber stack are first discharged to the atmosphere.

B. In cases where scrubber installation does not involve construction of a new stack or the installation of new (or relocated) continuous monitoring systems, proceed as follows:

(1) Conduct a 12-point stratification check of the scrubber effluent stream, at the CEM or reference method sampling location, in accordance with Section 6.5.6.1 of Appendix A to Part 75.

(2) No additional certification tests are required for the high-scale SO_2 monitor, provided that the high-scale has been previously certified in accordance with Part 75 requirements.

(3) No additional certification tests are required for the NO_x monitoring system or for the CO_2 pollutant monitor, provided that: (1) these monitors have been previously certified in accordance with Part 75 requirements;
(2) the results of the stratification check indicate that stratification is absent (using the criteria in Section 6.5.6.3(a) of Appendix A); and (3) if these monitoring systems are dilution extractive-type systems, the size of the critical orifice is not changed. If stratification is found to be present or the size of the critical orifice is changed, however, a normal-load RATA of these monitoring systems is required.

(4) If the low and high scales of the SO_2 monitor are on the same analyzer and differ only by a gain factor, a linearity check and 7-day calibration error test are the only tests required for the low-scale unless the results of the stratification test show stratification to be present or, if applicable, the size of the critical orifice is changed. If stratification is present or if the size of the critical orifice is changed, a low-scale RATA at normal load is also required.

If the low-scale SO_2 monitor is a different analyzer from the high-scale SO_2 monitor, all four certification tests (i.e., a linearity test, a 7-day calibration error test, a normal-load RATA, and a cycle/response time test) are required, irrespective of the results of the stratification test and whether or not the size of the critical orifice is changed.

(5) Update the monitoring plan to reflect the changes made to the SO_2 monitoring system. If the SO_2 low and high scales are on the same analyzer, you may either represent them as two components of the same system in RT 510 of the electronic monitoring plan or you may represent them as a single component, with a "component type code" of

"SO2A" in RT 510, column 23. If the low and high scales are two different analyzers, show them as separate monitoring systems.

(6) Recertification of the flow monitor (i.e., a 3-load RATA) is required.

II. **DATA REPORTING:**

A. All conditionally valid data generated by the primary Part 75 monitoring systems in the time interval (not to exceed 90 days) between the first hour of scrubber operation until the hour of completion of the CEM certification tests may be used for Part 75 reporting purposes, provided that the data validation requirements of § 75.20(b)(3) are met. Any data recorded by reference methods may also be used for reporting purposes.

B. Apply the appropriate bias adjustment factors to the CEMS data used for reporting (SO_2, NO_x, and flow rate, only), in accordance with the results of the RATA tests. Use a BAF of 1.000 until the hour of completion of the RATA. If a CEMS fails the bias test, calculate the BAF and apply it to the subsequent data from the CEMS, beginning with the hour after completion of the RATA (see Section 7.6.5 of Appendix A to Part 75).

C. Prior to provisional certification of a CEMS, for any hours in which no Reference Method data are available for reporting, provide substitute data for NO_x, flow rate, and CO_2, using Option 1, 2, or 3, below. For SO_2, Option 3 may be used without qualification; however, Option 1 or 2 may only be used if it can be demonstrated that the scrubber was working properly during the missing data period. This can be demonstrated by submitting to EPA all of the hourly information required by § 75.58(b)(1) along with the quarterly report. As part of the submittal to EPA, identify, for each parameter in § 75.58(b)(1), the range of acceptable values that indicates proper scrubber operation. The required hourly information must be provided for each hour of each missing data period in the interval from the initial hour of scrubber operation until the SO_2 monitor is provisionally certified. Report an MODC of 05 for any hours in which parametric data are used to determine missing data. If, for any hour of missing data, the scrubber is not working properly or the parametric data are not provided to EPA, SO_2 missing data must be substituted using Option 3.

(1) Maintain the connection to the historical (unscrubbed) data stream. In order to use this option, the unit-stack configuration must remain the same. For example, this option may be used if, both before and after installation of the scrubber, a unit emits through one stack. It may not be used, however, if two unscrubbed units which had previously emitted through separate stacks are connected to a common scrubber and now emit through one stack. Depending upon how many hours of historical quality-assured data were collected prior to installation of the scrubber,

apply whichever missing data procedures were in effect at the time of scrubber installation (i.e., either § 75.31, § 75.33, or § 75.34).

(2) Re-start the initial missing data procedures of § 75.31, beginning with the first hour of operation of the scrubbed unit. If this option is selected, reference method data collected prior to a missing data period may be used to provide quality-assured data for the missing data routines. For NO_x and flow rate, the reference method data in a particular load range may be used to provide substitute data for that load range or for any lower load range.

(3) Report using the maximum potential concentrations and/or flowrates and/or emission rates.

D. For hours in which some or all of the effluent from the affected unit(s) is diverted to a bypass stack, the emissions must either be measured by certified Part 75 monitoring systems, or the maximum potential values for SO_2 concentration, CO_2 pollutant concentration and total volumetric flowrate must be reported. For NO_x, report the maximum potential NO_x emission rate in lb/mmBtu.

E. Include in RT 910 of the electronic quarterly report (or in the cover letter that accompanies the quarterly report) the following information:

(1) The date and clock hour when the scrubbed unit(s) first operated;

(2) The dates and times of the certification tests of each of the monitoring systems used for "interim" data reporting (i.e., in the interval from initial scrubber operation until successful completion of the CEM certification tests);

(3) For each monitoring system used for interim data reporting, include the date and hour in which quality-assured data were first used for reporting (this date and time is considered to be the date and time of provisional certification for the monitoring system); and

(4) An explanation of the missing data procedures used for SO_2, NO_x, flow rate, and CO_2 in the interval between initial scrubbed unit operation and certification of the continuous monitoring systems.

F. Report the results of all daily calibrations used to validate the monitoring data used for interim data reporting, in RT 230.

G. Use the EDR Method of Determination Codes in Table 4A under § 75.57, in the usual manner.

H. At the end of the interim period (i.e., when either: (1) the certification tests of the monitoring systems have been completed; or (2) 90 days have elapsed since initial operation of the scrubbed unit), return to the normal Part 75 data validation and reporting procedures.

References: § 75.4(e), § 75.20(b)(3), § 75.31, § 75.33, § 75.57, § 75.58, § 75.66

Key Words: Certification tests, Control devices, Missing data, Reporting

History: First published in July 1995, Update #6; revised in October 1999 Revised Manual

Question 16.11 RETIRED

Question 16.12 RETIRED

Question 16.13 RETIRED

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SECTION 17
COMMON, MULTIPLE, AND COMPLEX STACKS

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Question 17.1 REVISED

Topic: Common Stack RATAs

Question: For a multi-unit situation where more than one unit feeds a common stack, how does EPA define low, medium, and high load for RATA purposes since there are numerous permutations or combinations in flows to the stack?

Answer: The method for determining the range of operation and the low, mid and high load levels for a unit or common stack is found in Section 6.5.2.1 of Appendix A to Part 75. For a common stack, the lower boundary of the range of operation is either: (1) the lowest minimum, safe stable load for any of the units discharging through the common stack; or (2) for a group of frequently-operated units, the sum of the minimum safe, stable loads of the individual units. The upper boundary of the range of operation is defined as the sum of the maximum sustainable loads for the individual units, unless that combined load is unattainable in practice, in which case, use the maximum sustainable combined load from a four quarter (minimum) historical lookback. The low, mid, and high load levels are expressed as percentages of the range of operation (0 - 30% of range = low, 30 - 60% = mid, and 60 - 100% = high).

References: Appendix A, Section 6.5.2.1

Key Words: Common stack, Flow monitoring, RATAs

History: First published in Original March 1993 Policy Manual; revised in October 1999 Revised Manual

Question 17.2 REVISED

Topic: Monitor Location

Question: Concerning our two units that are both Acid Rain affected and exit a common stack, the gas from each unit is mixed in the stack between five and six diameters upstream of the sampling location. Does Performance Specification 2 allow a traverse at 0.4, 1.2, and 2.0 meters within the stack or must we go by the percentages of centroid line (16.7, 50.0, 83.3)?

Answer: Section 3.2 of Performance Specification 2 (40 CFR Part 60, Appendix B) requires that traverse points based upon percentages of the centroid line be used unless concentration stratification in the stack is not expected. Due to uncertainty regarding whether the stack configuration described in the question allows sufficient time for gas mixing, the use of traverse points based upon percentages of the centroid line would be required unless testing to verify the absence of concentration stratification is conducted.

References: 40 CFR Part 60, Appendix B, PS 2 (3.2)

Key Words: Common stack, Monitor location

History: First published in Original March 1993 Policy Manual; revised in October 1999 Revised Manual

Question 17.3

Topic: Load Ranges

Question: In the common stack provisions concerning the load ranges for missing data substitution, there is mention of using twenty ranges with five percent increments (for flow rate data) instead of ten ranges with ten percent increments. Is this alternative an option or a requirement for two or more units monitored by a single monitoring system?

Answer: The use of twenty load ranges, rather than ten, is optional. Section 2.2.1 of Appendix C, which addresses missing data procedures for units sharing a common stack, indicates that the load ranges for flow may be broken down into twenty equally-sized operating load ranges, but this is not required.

References: Appendix C, Section 2.2.1

Key Words: Common stack, Flow monitoring, Missing data

History: First published in Original March 1993 Policy Manual

Question 17.4 RETIRED

Question 17.5 REVISED

Topic: Common Stack -- Heat Input Rate Apportionment

Question: Can a utility use the ratio of the load from a unit to the load from all of the units to apportion heat input rate to the units in a common stack?

Answer: Yes, provided that all units using the common stack are using fuel with the same f-factor. Use the gross electrical load or the gross steam load (flow) reported in RT 300 in the apportionment. Use Equation F-21a or Equation F-21b, as appropriate.

These equations should be included in the monitoring plan in RT 520. In RT 520, fill out separate heat input equations for each unit, with individual units filled in for each equation. The heat input rate apportionment formula must also be verified and included with the DAHS Verification Statement.

Other apportionment methods for heat input rate may be approved as petitions are received. Units at common stacks are also permitted to determine their heat input rates using fuel sampling and analysis using the procedures in Section 5.5 of Appendix F.

References: § 75.16(e)(3); Appendix F, Section 5.5

Key Words: Common stack, Heat input

History: First published in November 1993, Update #2; revised in October 1999 Revised Manual

Question 17.6 REVISED

Topic: NO_x Monitoring -- Multiple Stack Configurations

Question: For a single unit with a multiple stack or duct configuration, can the NO_x emission rate be measured in only one stack and still ensure that NO_x emissions are accounted for "during all times when the unit combusts fuel," as required by § 75.17(c)(2)?

Answer: Yes, depending on the type of unit, the specifics of the stack or duct configuration, and the way in which the unit is operated. Use the following guidelines:

GUIDELINES FOR BOILERS

(1) For a simple multiple stack configuration in which the flue gases from the unit are sent to two or more exhaust stacks, you may monitor NO_x emission rate using a single monitoring system installed on one stack, provided that:

(a) The products of combustion are sufficiently well-mixed to ensure that a NO_x emission rate representative of the unit can be obtained in any one of the stacks. As a guideline, the combustion products are considered to be well-mixed if test data or CEM data are available to show that the NO_x emission rates in the individual stacks differ by no more than 10% or 0.01 lb/mmBtu (whichever is less restrictive);

(b) The flue gases are never routed in such a manner that they will bypass the monitored stack; and

(c) For units with NO_x emission controls, the flue gases flowing through all of the individual stacks are controlled to the same level.

(2) For a single-stack unit with split or multiple breechings, if the owner or operator elects to monitor NO_x emission rate in the ductwork (breechings) rather than in the stack, you may monitor NO_x emission rate using a single monitoring system installed on one duct, provided that:

(a) The products of combustion are sufficiently well-mixed to ensure that a NO_x emission rate representative of the unit can be obtained in any one of the ducts (see guideline in (1)(a), above);

(b) The flue gases are never routed in such a manner that they will bypass the monitored duct; and

(c) For units with NO_x emission controls, the flue gases flowing through all of the individual ducts are controlled to the same level, and there are no additional NO_x emission controls downstream of the point at which the NO_x emission rate is monitored.

(3) For a configuration consisting of a main stack and a bypass stack, you may monitor NO_x emission rate with a single monitoring system installed on the main stack, provided that:

(a) You report the maximum potential NO_x emission rate (MER) for any hour in which flue gases flow through the bypass stack; and

(b) A method of determination code of "23" is reported for every hour in which flue gases flow through the bypass stack. Treat hours in which code "23" is reported as non-quality-assured hours (do not include these hours in the load ranges (bins) for missing data lookbacks).

If the applicable conditions in paragraph (1), (2), or (3) above are fully met and you elect to monitor NO_x emission rate at only one stack or duct, then:

! Report all of the NO_x emission data (EDR RTs 201, 210 (or 211), and 320) and the related NO_x quality-assurance data at the unit level. Do not use multiple stack ("MS") prefixes for NO_x reporting, even if you use MS prefixes for SO_2 and CO_2 reporting from the same unit.

! If a flow monitor is installed on each stack or duct, determine the hourly heat input rate at each stack using the applicable Appendix F equation. For each hour, use the CO_2 or O_2 reading from the NO_x-diluent CEMS in the heat input equation. Calculate the heat input rate at the unit level using Equation F-21C.

- For cases (1) and (2), above, if you should install an additional NO_x-diluent CEMS on any of the other stacks or ducts, designate it as a redundant backup system in your monitoring plan.

- For case (3), above, if a unit is CEMS-based and the bypass stack is completely unmonitored (i.e., if NO_x-diluent, SO_2, CO_2, flow rate, and moisture monitoring systems are installed on the main stack only), then for any hour in which the bypass stack is used, you must not only report the NO_x MER, but also the maximum potential concentration for SO_2 and CO_2, and the maximum potential flow rate. For moisture (if applicable), report the minimum potential moisture percentage.

- If the unit uses Appendix D and G methodology for SO_2 and CO_2, determine hourly SO_2 and CO_2 emissions in the normal manner during bypass hours. Also, determine the actual hourly heat input rates at the unit level, using the measured fuel flow rates and the fuel GCV value(s).

- Report the quarterly and cumulative arithmetic average NO_x emission rates for the unit in RT 301.

- Perform missing data substitution for NO_x emission rate at the unit level in RT 320.

- For further reporting guidance see the "Revised EDR Version 2.1 Reporting Instructions."

GUIDELINES FOR COMBUSTION TURBINES

(1) For combustion turbines that have both a main stack and a bypass stack, you may monitor NO_x emission rate using a single monitoring system installed on the main stack, as described in paragraph (3) under "GUIDELINES FOR BOILERS," above. If you choose this option, follow the applicable reporting guidelines in the bulleted items, above.

(2) For combustion turbines that have a main stack and a bypass stack, you may not monitor NO_x emission rate using a single, certified monitoring system installed on the bypass stack, except for an interim period while the heat recovery steam generator (HRSG) and the main stack are under construction. If you elect to monitor NO_x emissions from the bypass stack during this interim period, designate the NO_x monitoring system as a primary system in your monitoring plan. Report all NO_x emission data and heat input data at the unit level.

When construction of the HRSG and main stack is complete, if you wish to continue monitoring NO_x emission rate from only one stack, you must relocate the primary monitoring system to the main stack and recertify it. If you choose this option, keep the "primary" designation for the NO_x-diluent system in your monitoring plan and keep the same system and component ID numbers. While testing the monitoring system for recertification, you may either use conditional data validation procedures of § 75.20(b)(3) or you may use the Part 75 missing data routines until the system is recertified.

After recertifying the NO_x monitoring system at the main stack location, monitor the NO_x emission rate as described in paragraph (3) under "GUIDELINES FOR BOILERS," above. Follow the applicable reporting guidelines in the bulleted items, above.

If the guidelines and conditions for single-stack monitoring described above are not fully met, it is the responsibility of the utility to insure that NO_x emissions are accurately measured whenever an affected unit is combusting fuel. In these cases, owners and operators must install separate NO_x monitoring systems in each of the multiple stacks or ducts (see Policy Question 17.7).

References: § 75.17(c)

Key Words: Electronic report formats, Multiple stacks, NO_x monitoring, Reporting

History: First published in August 1994, Update #3; revised in October 1999 Revised Manual; revised in December 2000, Update #13

Question 17.7 REVISED

Topic: NO_x Monitoring -- Multiple Stack Configurations

Question: If I must measure the NO_x emission rate from all of the multiple stacks or ducts associated with a single unit, or if I choose to do so, how do I determine the NO_x emission rate for the unit?

Answer: If you have a unit with a multiple stack (or duct) configuration, and the unit does not qualify for single-stack (or duct) monitoring under Policy Question 17.6, you must monitor the NO_x emission rate in each of the multiple stacks or ducts separately. If you are required to monitor all of the stacks or ducts, or if you voluntarily choose to do so, use the following guidelines.

GUIDELINES FOR BOILERS

For boilers you may either:

(1) Identify separate NO_x emission rate monitoring systems with unique system IDs for each stack or duct and test and certify each system separately. Apply missing data procedures for each stack or duct separately. Calculate and

report the NO_x emission rates separately for each duct or stack (which has been identified in the monitoring plan with a multiple stack ("MS") prefix). Assign formula IDs to support the calculation of hourly NO_x emission rate and include these formulas in the monitoring plan.

In RT 301, calculate and report the quarterly and cumulative arithmetic average NO_x emission rate for each stack or duct . Also calculate and report the quarterly and cumulative heat input-weighted NO_x emission rates for the unit. See the EDR v2.1 Reporting Instructions (specifically, the instructions for RT 301, columns 36 and 49) for a discussion of these calculations; or

(2) If the unit uses Appendices D and G for SO_2 and CO_2 emissions accounting, monitor the NO_x emission rate separately at each stack or duct and, in lieu of installing a flow monitor on each stack or duct, you may report all hourly, quarterly and cumulative NO_x emission data at the unit level; provided that:

(a) For any hour in which flue gases exhaust through only one of the stacks, the NO_x emission rate measured at that stack is reported (or, if the monitoring system is out-of-control, the appropriate missing data value is reported); and

(b) For any hour in which flue gases exhausts through all of the stacks, report the highest NO_x emission rate measured by any of the installed monitoring systems. If any of the monitoring systems is out-of-control during a particular operating hour, report the higher of the appropriate missing data value for that hour or the measured value from the system that is not out-of-control.

If you use this option, designate each NO_x-diluent CEMS as a primary monitoring system in the monitoring plan. Perform missing data substitution for NO_x at the unit level. The reported quarterly and cumulative NO_x emission rates for the unit will be arithmetic average of the reported hourly Nox emission rates values.

GUIDELINES FOR COMBUSTION TURBINES

Monitor the NO_x emission rate at both the main HRSG stack and at the bypass stack. Report all hourly, quarterly and cumulative NO_x emission data and heat input data at the unit level. The reported quarterly and cumulative NO_x emission rates will be arithmetic averages. Perform missing data substitution at the unit level. Do not use multiple stack ("MS") prefixes. Designate both of the NO_x monitoring systems as primary systems in the monitoring plan (RT 510). Additionally, for purposes of reporting:

(1) For any hour in which flue gases exhaust through only one of the stacks, report the NO_x emission rate measured at that stack (or, if the monitoring system is out-of-control, report the appropriate missing data value); and

(2) For any hour in which flue gases exhaust through both of the stacks, report the higher of the two NO_x emission rates measured by the installed monitoring systems. If either or both of the monitoring systems is out-of-control during a particular operating hour, report the appropriate missing data value for that hour.

References: § 75.17(c)

Key Words: Electronic report formats, Multiple stacks, NO_x monitoring, Reporting

History: First published in August 1994, Update #3; revised in October 1999 Revised Manual; revised in December 2000, Update #13

Question 17.8

Topic: Definition of Boiler Emission Controls for NO_x Monitoring in Multiple Stacks or Ducts

Question: For units with multiple stacks or ducts, what types of NO_x controls require NO_x measurements on all stacks or ducts?

Answer: Any type of controls which would change the ratio of NO_x to CO_2 requires NO_x monitoring. These controls would be add-on emission controls for NO_x that are located on or after one or more of the stacks or ducts. Particulate controls such as an ESP after the boiler should not significantly affect the NO_x to CO_2 ratio and EPA would allow monitoring only in one of the ducts.

References: § 75.17(c)

Key Words: Multiple stacks, NO_x monitoring

History: First published in March 1995, Update #5

Question 17.9 REVISED

Topic: SO_2 Monitoring in Multiple Stacks or Ducts

Question: What are the requirements for SO_2 monitoring and reporting for a unit with multiple stacks or multiple ducts, when the monitoring systems are located in the ducts?

Answer: You must install and identify separate SO_2 and flow monitoring systems for each stack or duct in the monitoring plan. Use a unique system ID for each system in one stack or duct and a different system ID for the monitoring system of the same pollutant in the other stack or duct. Each system should be tested and certified separately. Missing data substitution procedures apply separately to each stack or duct as well.

Do not report hourly SO_2 mass emissions in RT 310 on a unit basis. Instead, for each hour of unit operation, report, for each stack or duct, one RT 200 for SO_2 concentration, one RT 220 for flow rate, and one RT 310 for SO_2 mass emissions. Provide quarterly and cumulative SO_2 mass emissions (in lb) in the RT 301 for each stack or duct as follows: (1) multiply each hourly mass emission rate reported in RT 310 for the stack or duct by the corresponding stack operating time in RT 300, column 18; and (2) take the sum of these products.

Report cumulative SO_2 mass emissions in RTs 301 only for the individual stacks or ducts in the multiple stack/duct configuration. Do not report the combined SO_2 mass emissions for the affected unit in a separate RT 301.

References: § 75.16

Key Words: Electronic report formats, Multiple stacks, Reporting, SO_2 monitoring

History: First published in March 1995, Update #5; revised in October 1999 Revised Manual

Question 17.10 REVISED

Topic: CO_2 Monitoring and Reporting for Multiple Stacks or Ducts

Question: What are the requirements for CO_2 monitoring and reporting for a unit with multiple stacks or ducts? Include a discussion of missing data requirements.

Answer: If you choose to use O_2 or CO_2 analyzers to calculate CO_2 mass emissions, install analyzers in all stacks or ducts. Calculate and report in RT 330 the CO_2 mass emission rate in tons/hr for each stack or duct separately.

Prior to April 1, 2000, the owner or operator may use standard missing data procedures in § 75.35(d) for CO_2, or may use Appendix G fuel sampling and analysis to estimate CO_2 mass emissions for the unit under § 75.35(c). If Appendix G sampling is used, do not report any hourly CO_2 mass emissions on a stack or duct basis in RT 330. Instead, report an hourly RT 330 for the unit. If you are using EDR v1.3, in the unit RT 330 leave the formula ID blank and indicate that Appendix G procedures were used for missing data by entering "13" as the Method of Determination Code.

After April 1, 2000, the owner or operator must use the revised missing data procedures in § 75.35(d). Note that use of Appendix G fuel sampling for missing data procedures is not allowed after April 1, 2000.

Provide quarterly and cumulative CO_2 mass emissions in the RT 301 for each stack or duct as follows: (1) multiply each hourly mass emission rate reported in RT 330 for the stack or duct by the corresponding stack operating time in RT 300, column 18; and (2) take the sum of these products.

Report cumulative CO_2 mass emissions in RTs 301 only for the individual stacks or ducts in the multiple stack/duct configuration. Do <u>not</u> report the combined CO_2 mass emissions for the affected unit in a separate RT 301.

References: § 75.13(c); Appendix G

Key Words: CO_2 monitoring, Electronic report formats, Excepted methods, Multiple stacks, Reporting

History: First published in March 1995, Update #5; revised in October 1999 Revised Manual

Question 17.11 REVISED

Topic: Heat Input Calculations and Reporting for Monitoring in Multiple Stacks or Ducts

Question: What are the requirements for heat input reporting for a unit using CEMS in multiple stacks or ducts?

Answer: You must calculate hourly heat input rate for each stack or duct individually and report this value in the RT 300 reported for that stack or duct. Calculate the hourly heat input rate for the unit by summing the heat input values for the corresponding stacks or ducts for that hour and dividing by the unit operating time (using Equation F-21c) and report that value in the RT 300 reported for the unit.

Provide quarterly and cumulative heat input data in RTs 301 for each stack or duct in the multiple stack or duct configuration. Also provide quarterly and cumulative *composite* heat input data for the affected unit (<u>i.e.</u>, the sum of the duct or stack heat inputs) in a separate RT 301.

For each stack or duct, determine the quarterly or cumulative heat input as follows: (1) multiply each hourly heat input rate for the stack or duct (as reported in RT 300, column 36) by the corresponding stack operating time in RT 300, column 18; and (2) take the sum of these products.

References: § 75.16

Key Words: Electronic report formats, Heat input, Multiple stacks, Reporting

History: First published in March 1995, Update #5; revised in October 1999 Revised Manual

Question 17.12 REVISED

Topic: Operating Data for Monitoring in Multiple Stacks or Ducts

Question: What are the requirements for reporting operating data for a unit using CEMS in multiple stacks or ducts?

Answer: For any quarter in which the unit operates at all, RTs 300 must be submitted for all hours in the quarter for both the unit and the stacks or ducts. If, during any unit operating hour, the damper to a particular stack or duct is completely closed and the monitors in the stack or duct are recording zero emissions, report an operating time of zero (0.00) for that stack or duct, indicating a non-operating status for the hour.

References: § 75.64

Key Words: Electronic report formats, Multiple stacks, Reporting

History: First published in March 1995, Update #5; revised in October 1999 Revised Manual

Question 17.13 REVISED

Topic: Multiple Stacks -- NO_x Emission Rate Calculations

Question: I have a unit with multiple stacks. I am determining the unit NO_x emission rate using a heat input weighted average of the emission rates in each stack. How do I calculate the NO_x emission rate for the unit when I have to do fuel sampling to determine heat input during long outages of a diluent monitor?

Answer: After April 1, 2000, fuel sampling will not be used to determine heat input during diluent monitor missing data periods. If the owner or operator continues to use the fuel sampling procedure for missing data prior to that date (as specified in § 75.36(c)), calculate a flow weighted average of the NO_x emission rates at each stack for those hours. Note that because a diluent monitor is not operating, the NO_x emission rate at one or more of the stacks will be substituted using missing data procedures. The substituted NO_x emission rate will be then included in the flow weighted average.

References: § 75.36(d); Appendix F, Section 5

Key Words: Heat input, Missing data, Multiple stacks, NO_x monitoring

History: First published in July 1995, Update #6; revised in October 1999 Revised Manual

Question 17.14 REVISED

Topic: Reporting Partial Operating Hours for Multiple Stack Units

Question: A unit has two stacks and a damper that can direct emissions from one stack to the other. Suppose that emissions go through one stack from 10:00 AM to 10:18 AM, and from 10:19 AM to 10:59 AM through the other stack. How many operating hours should be reported in RT 300 for each stack and for the unit?

Answer: You may report the actual portion of the hour in which each stack was used, to the nearest hundredth of an hour (0.30 operating hours for the first stack, 0.67 operating hours for the second stack, and 1.00 operating hours for the unit). Alternatively, you may report the number of quarter hours in which each stack was used (0.50 operating hours for the first stack, 0.75 for the second stack, and 1.00 operating hours for the unit).

References: § 75.57(b); RT 300

Key Words: Electronic report formats, Multiple stacks

History: First published in July 1995, Update #6; revised in October 1999 Revised Manual

SECTION 18
CONVERSION PROCEDURES

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Question 18.1

Topic: F-factors During Co-firing

Question: When burning more than one fuel in a boiler during startup or shutdown, what F-factor should be used?

Answer: If accurate measurement of quantities of both fuels can be determined, use the BTU weighted average procedure specified in Part 75, Appendix F (Sections 3.3.5 and 3.3.6.4). However, if measurement of the startup/shutdown fuels cannot be accurately determined, then during the transition periods of co-firing use the F-factor that will produce the higher NO_x emission rate in order to prevent under-reporting of emissions.

References: Appendix F, Sections 3.3.5 and 3.3.6.4

Key Words: Conversion procedures, F-factors

History: First published in Original March 1993 Policy Manual

Question 18.2 RETIRED

Question 18.3 RETIRED

Question 18.4

Topic: Load and Heat Input Rate Determination for Combustion Turbines

Question: For combustion turbines, how do I report unit load and heat input rate in EDR RT 300?

Answer: EPA requires utilities to report all of the hourly heat input to the unit and to report a consistent measure of unit load. Therefore:

(1) For a simple combustion turbine without a heat recovery steam generator (HRSG), or a for a combustion turbine (CT) that has an HRSG but does not have auxiliary firing, report the hourly heat input rate to the CT in column 36 of RT 300. In column 22 of RT 300, report the electrical output (in megawatts) from the generator that serves the CT; or

(2) For a combustion turbine that has both an HRSG and auxiliary firing, report the combined hourly heat input to the CT and the auxiliary combustion source(s) in column 36 of RT 300. Report the hourly load in megawatts, as the sum of: (1) the electrical output from the generator that serves the CT; and (2) the "equivalent" electrical output produced by the auxiliary combustion source. Report the sum of these outputs in column 22 of RT 300. Use the following equation to convert the hourly heat input to the auxiliary combustion source to an equivalent electrical output:

$$L_{eq} = HI \times 10^6 \frac{Btu}{mmBtu} \times E \times \frac{1\,kw-hr}{3{,}413\,Btu} \times \frac{MW}{1000\,kw}$$

Where:

L_{eq} = Equivalent hourly electrical load, from auxiliary combustion source, (megawatts)

HI = Hourly heat input to the auxiliary combustion source, (mmBtu/hr)

E = Percentage efficiency of the auxiliary combustion source (use actual, measured efficiency, if available, or a default value of 33%)

References: § 75.57(b)

Key Words: Conversion procedures, Reporting

History: First published in March 1995, Update #5; Revised in December 2000, Update #13

Question 18.5 REVISED

Topic: Missing F-factor Data

Question: If an Appendix D unit is burning multiple fuels and the owner/operator has chosen to determine their NO_x emissions based on a prorated F-factor calculated from the heat input from each fuel, how should they determine the NO_x emissions for an hour in which they are missing heat input data for one of the fuels?

Answer: Use the F-factor from the fuel with the highest F-factor that is burned in a given hour.

References: Appendix D, Section 2.4; Appendix F, Section 3

Key Words: Excepted methods, F-factors, Missing data, NO_x monitoring

History: First published in July 1995, Update #6; revised in October 1999 Revised Manual

Question 18.6

Topic: Site-specific Fuel Factor

Question: How would the Agency view the use of a site-specific fuel factor for several plants operated by a utility instead of the generic fuel factor listed in Table 1 of Appendix F to Part 75? The site-specific fuel factor would use Equation F-7b listed in Section 3.3.6 of Appendix F to provide the correct fuel factor for the coal combusted at a specific site. The fuel factor for any given year would be based upon the average of 24 or more coal analyses from the previous year; it would remain constant for the entire year and be updated in January of each year. All emission calculations that require the use of a fuel factor for CEM systems would use the site specific fuel factor, including RATA calculations.

Answer: The utility may petition the EPA to implement this approach. The EPA believes this approach has merit but would like the utility to petition with specific technical details and data to demonstrate that there is little variability with the fuel factor and that this approach will not underestimate emissions.

References: Appendix F, Section 3.3.6

Key Words: F-factors, Petitions

History: First published in November 1995, Update #7

Question 18.7 NEW

Topic: Maximum Hourly Gross Load for Combustion Turbines

Question: For combustion turbines, how do you establish the missing data load ranges (load "bins") required under section 2.2.1 of Appendix C?

Answer: Establish the load ranges in terms of percent of the maximum hourly gross load (MHGL) of the unit. If the turbine is the only combustion source (i.e., if there is no auxiliary firing), use the following equation to determine the MHGL and use the result to establish the missing data load ranges:

$$MHGL = HI_{max} \times 10^6 \frac{Btu}{mmBtu} \times E \times \frac{1\,kw-hr}{3{,}413\,Btu} \times \frac{MW}{1000\,kw}$$

Where:
MHGL = Maximum hourly gross load, (megawatts)
HI_{max} = Maximum rated hourly heat input of the turbine, (mmBtu/hr)

E = Percentage efficiency of the unit (use actual, measured efficiency or default value of 50%)

If the unit has auxiliary firing (e.g., a duct burner installed on a heat recovery steam generator or an auxiliary boiler), use the above equation twice, (once to determine the maximum load for the turbine and a second time to determine the maximum equivalent electrical load for the auxiliary combustion source(s)). When using the equation for the auxiliary combustion source(s), replace the word "turbine" with the words, "auxiliary firing" and use a default value of 33% efficiency if the actual, measured percent efficiency is not available. Add together the maximum loads for the turbine and auxiliary combustion source(s) and use the total load to establish the missing data load ranges.

References: Appendix C, Section 2.2.1

Key Words: Hourly load, Load ranges, Maximum, Missing data

History: First published in December 2000, Update #13

SECTION 19
APPLICABILITY

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Question 19.1

Topic: New Unit Exemptions

Question: If a new unit that is required to operate a CEMS under Subpart Db of 40 CFR Part 60 is under the 25 MWe size classification provided in the final Part 75 rule and burns gas or diesel oil only, is this unit subject to any of the monitoring or permitting requirements of the Title IV regulations?

Answer: In accordance with the provisions of § 72.7 and § 75.2(b)(1), such a unit would be exempt from Acid Rain permitting and CEM requirements if it burns only fuels with a sulfur content of 0.05 weight percent or less. In order to qualify for these exemptions, the designated representative for the unit must submit a petition in accordance with the provisions of § 72.7(b). Units below the 25 MWe size classification that burn fuels with a sulfur content of greater than 0.05 weight percent would be subject to all applicable permitting and CEM requirements in the Acid Rain rules.

References: § 72.7, § 75.2(b)(1)

Key Words: Exemptions, Gas-fired units, Oil-fired units

History: First published in Original March 1993 Policy Manual; revised May 1993, Update #1

Question 19.2 REVISED

Topic: Diesel-fired Units

Question: Is a combustion turbine firing #2 fuel oil considered a diesel-fired unit, and therefore, exempt from opacity monitoring requirements?

Answer: 40 CFR 72.2 defines diesel fuel as "a low sulfur fuel oil of grades 1-D or 2-D, as defined by the American Society for Testing and Materials standard ASTM D 975-91, 'Standard Specification for Diesel Fuel Oils,' grades 1-GT or 2-GT, as defined by ASTM D2880-90a, 'Standard Specification for Gas Turbine Fuel Oils,' or grades 1 or 2, as defined by ASTM D396-90a, 'Standard Specification for Fuel Oils'."

A combustion turbine would be considered a diesel-fired unit for purposes of the monitoring requirements in Part 75 if it uses primarily diesel fuel, and uses only gaseous fuels as a secondary fuel source. This type of diesel-fired combustion turbine would be exempt from opacity monitoring.

References: § 72.2

Key Words: Applicability, Oil-fired units

History: First published in May 1993, Update #1; revised July 1995, Update #6; revised in October 1999 Revised Manual

SECTION 20
JURISDICTION AND ENFORCEMENT

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Question 20.1 REVISED

Topic: Test Observations

Question: Who will coordinate the observation of certification tests?

Answer: The EPA Regional Representative will coordinate the observation of the certification tests. In some cases the State Representative will assist the Regional Representative and will perform on-site activities including observing certification tests.

References: N/A

Key Words: Certification tests, Jurisdiction

History: First published in Original March 1993 Policy Manual; revised in October 1999 Revised Manual

Question 20.2 REVISED

Topic: State Agency Role

Question: What will be the role of State air pollution control personnel? Will dual report filings be required?

Answer: State air pollution control personnel will participate in implementation of the Acid Rain CEM Rule. Although the degree of participation may vary from State to State, activities in which State personnel are likely to participate are monitoring plan review, certification test observation, and certification application evaluation. According to the notification and report submittal requirements promulgated at § 75.60(b) and § 75.61 through §75.63, copies of certification or recertification test notifications, certification or recertification applications and monitoring plans generally must be submitted to the EPA Administrator, appropriate EPA Regional Office, and appropriate State or local pollution control agency. Note, however, that the rule does not require the DR or ADR to provide EPA Headquarters with a copy of the hardcopy information for monitoring plans and certification/recertification applications. In addition, one or more of the applicable agency offices may waive requirements related to recertification test notices, and only the State/local agency needs to receive notice of opacity certification/recertification tests.

Quarterly reports (except for opacity reports) will be filed only with EPA Headquarters; opacity reports are sent only to the applicable State/local agency. Furthermore, any filings currently required by existing State or Federal programs outside the scope of the Acid Rain Program would still be required.

References: § 75.60(b), §§ 75.61 - 75.64

Key Words: Jurisdiction, Notice, Reporting

History: First published in Original March 1993 Policy Manual; revised in October 1999 Revised Manual

Question 20.3 REVISED

Topic: Enforcement

Question: How will compliance with the Title IV regulations and permits be enforced within EPA?

Answer: The EPA will continue to pursue a vigorous enforcement policy against violators of the Clean Air Act and its Amendments. As far as the specific provisions of the Acid Rain Rules are concerned, the enforcement roles of the EPA Regional Office, EPA Headquarters, and the State and local programs, and the overall compliance/enforcement guidance for the Acid Rain Program, are contained in a June 27, 1994 guidance document available on EPA's Web site (see: http://www.epa.gov/oeca/ore/aed/comp/gcomp.html).

References: N/A

Key Words: Enforcement, Jurisdiction

History: First published in Original March 1993 Policy Manual; revised in October 1999 Revised Manual

SECTION 21
REFERENCE METHODS
AS BACKUP MONITORS

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BACKGROUND

Section 75.24(c)(2) of the Acid Rain CEM Regulations (40 CFR Part 75) allows the use of EPA Reference Methods for data collection and reporting whenever a primary monitoring system is out-of-control. Section 75.20(d) of Part 75 further states that gas analyzers that qualify as reference method (RM) analyzers under 40 CFR 60, Appendix A (in particular, under instrumental Reference Methods 6C, 7E, and 3A for SO_2, NO_x, and CO_2/O_2, respectively) may be used as backup monitors. Such analyzers do not need to be certified prior to use.

POLICY

The following policy guidance, in question-and-answer format, outlines the general procedures to be followed when EPA Reference Methods are adapted for use as backup monitoring systems to collect data for Part 75 reporting. Note that the procedures and guidelines set forth in this policy, which include certain procedural changes and modifications to EPA Methods 6C, 7E, and 3A (especially pertaining to the use of dilution-type sampling systems), are specific to Part 75 Acid Rain monitoring applications, and are not necessarily appropriate for use in other programs.

Question 21.1

Topic: Reference Method Backup Monitors

Question: As written, instrumental Reference Methods 6C, 7E, and 3A specify the use of transportable, extractive-type measurement systems. As an alternative to a transportable system, would it be acceptable, under § 75.20(d), for a Part 75 reference method backup monitoring system to consist of a stack-mounted probe and its associated sample interface, connected to one or more reference method analyzers?

Answer: Yes, provided that: (1) the stack-mounted probe and sample interface are components of a **certified** Part 75 monitoring system; and (2) the reference method (RM) measurement system meets the applicable performance specifications of, and is operated in accordance with the procedures of, Method 6C, 7E, or 3A, supplemented (for dilution-type RM systems) by the special instructions given in this policy guidance document.

References: § 75.20, § 75.22, § 75.24

Key Words: Backup monitoring, Reference methods

History: First published in March 1995, Update #5

Question 21.2

Topic: Dilution Systems and Reference Method Applications

Question: Is it acceptable to use an in-stack dilution probe or an out-of-stack (ex-situ) dilution device as part of a Reference Method 6C, 7E, or 3A measurement system that is used for Part 75 backup monitoring and/or RATA applications?

Answer: Yes. Either an in-stack dilution probe or an ex-situ dilution device may be used as part of a Reference Method 6C, 7E, or 3A system. The Emission Measurement Branch of the Office of Air Quality Planning and Standards of EPA has authorized the use of dilution probes with the instrumental reference methods and has published guidance on this issue (EMTIC GD-18; June 10, 1992).

In order to apply dilution sampling techniques to Reference Methods 6C, 7E, and 3A, certain procedural changes to the subject methods and modifications to the performance requirements are necessary. For Part 75 applications, these variations are discussed in the questions below.

References: § 75.20, § 75.22, § 75.24

Key Words: Backup monitoring, RATAs, Reference methods

History: First published in March 1995, Update #5

Question 21.3

Topic: Method 6C and 7E Restrictions

Question: Are there any restrictions on the types of equipment that may be used in Part 75 backup Reference Method monitoring systems?

Answer: Yes. Section 1.2 of Method 6C specifies that SO_2 Reference Method (RM) analyzers must be either ultraviolet, nondispersive infrared(NDIR) or fluorescent. Section 5.1.3 of Method 7E specifies that NO_x RM analyzers must be chemiluminescent. In addition, § 5.1.11 of Method 6C requires the resolution of the data recorder to be 0.5% of span.

References: § 75.20, § 75.22, § 75.24; 40 CFR Part 60 Appendix A

Key Words: Backup monitoring, Reference methods

History: First published in March 1995, Update #5

Question 21.4 REVISED

Topic: Use of RM Backup Systems for RATA Testing

Question: Is it acceptable to use a Reference Method backup monitoring system to collect reference method test data during a required semiannual or annual relative accuracy test audit (RATA) of another Part 75 monitoring system?

Answer: Yes, provided that: (1) the applicable RATA procedures in Section 6.5 of Appendix A to Part 75 are followed; and (2) the procedures of RM 6C, 7E, and/or 3A, supplemented (for dilution-type RM systems) by the special instructions given in this policy guidance document, are followed.

References: § 75.20, § 75.22, § 75.24, Appendix A, Section 6.5

Key Words: Backup monitoring, RATAs, Reference methods

History: First published in March 1995, Update #5; revised in October 1999 Revised Manual

Question 21.5

Topic: Definition of NO_x RM Backup Monitoring Systems

Question: Is it acceptable, for Part 75 data reporting, to use a mix-and-match NO_x/diluent monitoring system consisting of the pollutant analyzer of a certified Part 75 NO_x/diluent system and a RM backup diluent analyzer (or vice-versa)?

Answer: No. Part 75 RM backup NO_x monitoring systems must consist of two reference method analyzers. Mix-and-match systems may not be used because of the uncertainty in the bias adjustment factors for such systems.

References: § 75.20, § 75.22, § 75.24

Key Words: Backup monitoring, NO_x monitoring, Reference methods

History: First published in March 1995, Update #5

Question 21.6

Topic: Span and Range Settings for RM Backup Monitoring Systems

Question: When instrumental Reference Methods are used as backup Part 75 monitors, what are the proper span values and full-scale range settings for the measurement systems?

Answer: The span values for RM backup monitoring systems are not determined in the same manner as the span values of Part 75 monitors. Rather, the span of each RM backup monitor must be set in a manner consistent with § 2.1 of Method 6C or § 2 of Method 3A, as appropriate. Some interpretation of these sections is required, because RM 6C, 7E, and 3A are designed for use in the NSPS program and the span value is constrained relative to an emission limit.

Therefore, for Part 75 applications, select the analyzer span value such that the RM measurements will be no less than 20% of span. The span value may be either equal to the full-scale range of the analyzer or a linear portion of the analytical range (see § 2.1 of RM 6C).

References: Appendix A, Section 2.1; 40 CFR Part 60 Appendix A

Key Words: Backup monitoring, Reference methods, Span

History: First published in March 1995, Update #5

Question 21.7 REVISED

Topic: Calibration Gases and RM Backup Monitoring

Question: What calibration gas concentrations are needed to operate a Part 75 backup RM monitor?

Answer: Two EPA Protocol gases (mid-level and high-level) are needed. A zero-level gas is also required. The proper concentrations of the gases are defined in terms of the analyzer span value for the instrumental method (see §§ 5.3.1 - 5.3.3 of Method 6C), and are as follows:

(1) Zero-level: < 0.25% of the span value. For O_2 monitors which cannot analyze zero gas, a concentration < 10% of span may be used (see § 5.2 of RM 3A).

Zero air material or purified ambient air may be used as the zero-level gas; see Question 10.2 for a further discussion.

(2) Mid-level: 40 to 60% of span value; and

(3) High-level: 80 to 100% of span value.

References: § 75.20, § 75.22, § 75.24; 40 CFR Part 60 Appendix A

Key Words: Backup monitoring, Calibration gases, Reference methods

History: First published in March 1995, Update #5; revised in October 1999 Revised Manual

Question 21.8 REVISED

Topic: Use of Calibration Gas Dilution Devices with Reference Methods

Question: Is it permissible to use calibration gas dilution devices with instrumental Reference Methods?

Answer: At the present time, gas dilution devices (such as those described in EPA Method 205), which enable the tester to generate calibration gases of various compositions from a single, high-concentration cylinder of Protocol gas, may <u>not</u> be used for Part 75 RM backup monitoring or RATA applications. However, EPA will consider allowing the use of gas dilution devices if demonstration data are provided to show that for linearity checks and RATAs performed using the dilution device, the test results are equivalent to those obtained using undiluted Protocol gases.

References: § 75.20, § 75.22, § 75.24; 40 CFR 51, Appendix M, Method 205

Key Words: Backup monitoring, Calibration gases, Reference methods

History: First published in March 1995, Update #5; revised in October 1999 Revised Manual

Question 21.9

Topic: RM Backup System Calibration Error and System Bias Checks

Question: Are separate system calibration error checks and system bias checks necessary for Part 75 Reference Method backup monitoring systems?

Answer: For non-dilution RM systems, separate 3-point analyzer calibration error checks prior to the commencement of any test runs and 2-point system bias checks before and after each run are required by Reference Methods 6C, 7E, and 3A.

For **dilution-type** RM systems, it is technically infeasible to perform the 3-point analyzer calibration error check required by § 6.3 of RM 6C, because the low range of the analyzers precludes direct injection of undiluted calibration gases at the analyzer. In addition, the concept of system bias cannot be applied to dilution systems because the results of system calibrations cannot be referenced to calibrations of the isolated analyzers.

Therefore, for dilution-type RM systems, perform a system calibration error test, which checks the entire system from probe to analyzer. An initial 3-point system calibration error test is required, prior to commencing any runs, using the zero, mid, and high-level gases. Thereafter, a 2-point system calibration error check is performed after each run, using the zero-level gas and whichever upscale gas (mid or high) is closest to the actual source emissions. The system calibration error is calculated as follows:

$$System\ Calibration\ Error = \frac{System\ Cal\ Response - Cal\ Gas\ Value}{Span\ Value} \times 100$$

References: § 75.20, § 75.22, § 75.24; 40 CFR Part 60, Appendix A

Key Words: Backup monitoring, Quality assurance, Reference Methods

History: First published in March 1995, Update #5

Question 21.10

Topic: Acceptable Calibration Error for RM Backup Monitoring

Question: For Part 75 RM backup monitoring systems, how much calibration error is acceptable in the pre-and post-test calibrations?

Answer: Methods 6C, 7E, and 3A allow calibration errors of up to ± 2% of span at each point for the 3-point pre-test analyzer calibration error check and ± 5% of span for pre- and post-run system bias checks when a non-dilution-type extractive monitoring system is used.

For dilution systems, a total system calibration error of ± 2 % of span at each point is allowed for the initial 3-point system calibration error check. For the subsequent 2-point system calibration error checks, the system calibration error must be within ± 5% of span.

References: § 75.20, § 75.22, § 75.24; 40 CFR Part 60, Appendix A

Key Words: Backup monitoring, Quality assurance, Reference methods

History: First published in March 1995, Update #5

Question 21.11

Topic: Validation of RM Backup Data

Question: What criteria are used to validate a test run when a Part 75 RM backup monitoring system is used?

Answer: For non-dilution-type monitoring systems, the run is validated if the RM system passes the post-run system bias checks. For dilution-type RM backup systems, a run is validated if the CEMS passes the post-run system calibration error checks. Whenever a RM backup monitor test run is invalidated, the Part 75 missing data procedures must be applied to fill in data for each hour of the test run.

References: § 75.20, § 75.22, § 75.24

Key Words: Backup monitoring, Missing data, Quality assurance, Reference methods

History: First published in March 1995, Update #5

Question 21.12

Topic: RM Backup Monitor Zero and Calibration Drift Checks

Question: Are zero and calibration drift checks necessary for Part 75 RM backup monitors?

Answer: Yes. For non-dilution extractive systems, the zero and calibration drift (i.e., the difference between pre-run and post-run system bias responses) allowed by RM 6C, 7E, and 3A is ± 3% of span.

For dilution systems, the allowable drift (i.e., the difference between pre-run and post-run system calibration error responses) is also ± 3% of span.

Exceeding the drift limit does not invalidate the run. However, a 3-point analyzer calibration error test (or a 3-point system calibration error test for dilution-type systems) must be successfully completed before additional test runs are conducted. For non-dilution-type systems, a system bias test is also required before proceeding.

References: § 75.20, § 75.22, § 75.24, 40 CFR Part 60, Appendix A

Key Words: Backup monitoring, Quality assurance, Reference methods

History: First published in March 1995, Update #5

Question 21.13

Topic: RM Backup System Calibration Error and System Bias Data

Question: For Part 75 RM backup monitoring systems, is it permissible to use the data obtained during the post-run system calibration error or system bias checks as the pre-run data for the next run?

Answer: Yes, but **only** if the post-run results indicate that all of the applicable calibration error, bias and calibration drift specifications have been met.

For dilution-type RM backup systems, use two of the three data points obtained during the initial 3-point system calibration error check as the two pre-run calibration values for the initial RM run. Note that this necessitates double-reporting of the two common data points in EDR RT 261 (see Question 21.34).

References: § 75.20, § 75.22, § 75.24; 40 CFR Part 60, Appendix A

Key Words: Backup monitoring, Quality assurance, Reference methods

History: First published in March 1995, Update #5

Question 21.14

Topic: Frequency of RM System Calibration Error and System Bias Checks

Question: How often must the 3-point analyzer calibration error check (for non-dilution-type RM systems) or the 3-point system calibration error check (for dilution-type systems) be performed?

Answer: The 3-point analyzer or system calibration error check is required before any RM test runs are initiated. Thereafter, the test does not have to be repeated so long as an unbroken sequence of RM test runs is conducted and the RM analyzer continues to pass the post-run bias (or calibration error) and drift checks. However, if two or more hours elapse between the ending and beginning times of successive test runs **or** if any required post-run check (i.e., system bias, system calibration error, zero drift, or calibration drift) is failed, the 3-point calibration must be repeated before any more RM runs are done (see § 7.4.2 of RM 6C).

In addition, § 6.4.2 of RM 6C requires the operator to repeat the 3-point analyzer calibration error check (or 3-point system calibration error check for dilution systems) after any adjustments are made to the RM analyzer calibration. For non-dilution-type RM systems, this must be followed by a system bias test before the next test run may begin.

References: § 75.20, § 75.22, § 75.24; 40 CFR Part 60, Appendix A

Key Words: Backup monitoring, Quality assurance, Reference methods

History: First published in March 1995, Update #5

Question 21.15 REVISED

Topic: Dilution-type RM Backup Monitoring Systems

Question: Are there additional procedural variations or special considerations to take into account when using a dilution-type RM backup monitoring system? Also, is it acceptable to use a dilution-type reference method for Part 75 RATA applications?

Answer: Yes, to both questions. In order to obtain consistent and accurate results with a dilution-type system, it is essential to take into account the following:

(1) The critical orifice size and dilution ratio must be selected properly, to ensure that the water and acid dewpoints of the diluted sample will be below the sample line and instrument temperatures.

(2) A high quality, accurate probe controller must be used, to carefully maintain the proper dilution air pressure and ratio during sampling.

(3) A correction for gas density effects may be desirable, because differences in molecular weight between calibration gas mixtures and stack gas affect the dilution ratio, and can cause measurement bias.

At present, the exact nature and magnitude of these gas density effects is not well understood; however, in a recent collaborative study which directly compared dilution-type RM measurement systems against dry-basis extractive systems, the gas concentrations read by the dilution systems were consistently higher (as much as 3% to 5%) than the moisture-corrected dry-basis concentrations (see "Collaborative Evaluation Summary" document included in Appendix C of this document).

For Part 75 RM backup and RATA applications, it is left to the discretion of the tester whether or not to correct the RM data for gas density effects. If such corrections are deemed necessary, a petition, explaining the mathematical equations and/or factors that will be used, must be submitted to and approved by the Administrator, in accordance with § 75.66(f).

References: § 75.20, § 75.22, § 75.24, § 75.66(f)

Key Words: Backup monitoring, Quality assurance, Reference methods

History: First published in March 1995, Update #5; revised in October 1999 Revised Manual

Question 21.16 REVISED

Topic: Selection of RM Backup Monitor Sampling Location and Points

Question: How are the sampling site and measurement points selected for Part 75 RM backup gas and flow rate monitoring systems?

Answer: **GAS MONITORS**: Use the following siting and point location guidelines for Part 75 RM backup monitoring systems:

Sampling Location

The RM sampling site must be selected to ensure representative measurement of the actual emissions discharged to the atmosphere from the unit or stack. Follow the guidelines of Section 6.5.5 of Appendix A to Part 75 (i.e., the sampling location must be: (a) accessible; (b) in the same proximity as the CEMS location; and (c) meet the requirements of Performance Specification (PS) 2 in Appendix B to Part 60).

Sampling Point(s)

Follow the guidelines of Section 6.5.6 of Appendix A to Part 75 (i.e., the RM sampling point(s) must: (a) ensure that representative concentration measurements are obtained; and (b) meet the requirements of PS 2). To achieve this, the tester has the following options:

(1) Use three traverse points per test run, located in accordance with § 3.2 of PS 2, and sample for an equal amount of time at each point;

(2) Use a single, representative sampling point that meets the location criteria in (a) or (b), below:

(a) The selected point is acceptable if located within 30 cm of the measurement point of an installed, certified Part 75 gas monitoring system. (The RM probe may be located up to 2 feet above or below the plane of measurement of the installed CEMS; however, when the RM probe is projected onto the CEMS measurement plane, the CEM and RM sample points must be separated by 30 centimeters or less.)

or

(b) The selected point is acceptable if it is no less than 1.0 meters from the stack wall and is demonstrated to be representative of the source emissions by means of a 12-point stratification test for the pollutant(s) to be monitored. Conduct the stratification test in accordance with Section 6.5.6.1 of Appendix A to Part 75. In order for the selected point to be suitable for RM backup monitoring, the point must meet the acceptance criteria in Section 6.5.6.3(b) of Appendix A.

FLOW MONITORS: The sampling site and measurement point locations must conform to the requirements of EPA Reference Methods 1 and 2.

References: § 75.20, § 75.22; Appendix A, Sections 6.5.5 and 6.5.6

Key Words: Backup monitoring, Reference methods, Sampling location

History: First published in March 1995, Update #5; revised in October 1999 Revised Manual

Question 21.17

Topic: System Response Time and RM Backup Monitoring

Question: What is meant by the "system response time" of a Part 75 RM backup gas monitoring system?

Answer: The system response time is the time required for the RM analyzer to give a stabilized reading, in response to step changes in calibration gas concentrations during the pre-test system calibration error tests (for dilution systems) or during the pre-test system bias checks (for non-dilution-type systems). Specifically, the system response time is the time needed for the measurement system to display 95 percent of a step change in gas concentration on the data recorder. Round off the system response time to the nearest minute (see §§ 3.8 and 6.4.1 of RM 6C).

References: § 75.20, § 75.22, § 75.24; 40 CFR Part 60, Appendix A

Key Words: Backup monitoring, Reference methods

History: First published in March 1995, Update #5

Question 21.18

Topic: Run Length and Frequency for RM Backup Gas Analyzers

Question: What is the proper run length for Part 75 RM backup gas monitors?

Answer: Run times of 1 hour or less (but no shorter than 20 minutes) are **recommended**. However, run lengths of up to **eight (8)** hours are permissible for Part 75 RM backup monitoring systems. There is no specified run length in RM 6C, 7E, or 3A. Section 8 of RM 6C refers both to run lengths of less than one hour and greater than one hour. Note, however, that as the length of a test run increases, the likelihood of an analyzer failing the post-test bias or system calibration error test also increases.

References: § 75.20, § 75.22, § 75.24

Key Words: Backup monitoring, Reference methods

History: First published in March 1995, Update #5

Question 21.19

Topic: Minimum Data Requirements and Data Reduction for RM Backup Test Runs

Question: What is the minimum required number of data points per run for Part 75 RM backup gas monitors, and how are the raw data reduced to hourly averages?

Answer: When the run length is $\geq$1 hour, Methods 6C, 7E, and 3A require either: (1) measurement at 1-minute intervals; or (2) a minimum of 30 evenly-spaced measurements per run (whichever is less restrictive).

When the run length is > 1 hour, the methods require either: (1) measurement at 2-minute intervals; or (2) obtainment of a minimum of 96 evenly-spaced measurements (whichever is less restrictive).

Only those measurements obtained after twice the system response time has elapsed are to be used to determine the pollutant or diluent concentrations (see §§ 7.3 and 8 of RM 6C).

RM backup monitoring data must also meet the minimum data capture requirement for continuous monitoring systems in § 75.10(d)(1) (i.e., obtaining a minimum of one valid data point in each 15-minute quadrant of each unit operating hour, except when required quality assurance activities are conducted during the hour, in which case, only two 15-minute quadrants need to be represented. The calibration error, bias and drift checks of RM 6C, 7E, and 3A fall within the definition of required quality assurance activities).

The raw data from each run are reduced to hourly averages as follows: For each individual clock hour of the run, calculate the (unadjusted) arithmetic average of **all** valid data points obtained during that hour. Then, calculate the adjusted hourly average for each clock hour of the run, using the appropriate equations of Method 6C, 7E, or 3A (see Question 21.28).

References: § 75.20, § 75.22, § 75.24; 40 CFR Part 60, Appendix A

Key Words: Backup monitoring, Data reduction, Data validity, Reference methods

History: First published in March 1995, Update #5

Question 21.20 REVISED

Topic: Stack Gas Moisture and RM Backup Monitoring

Question: Does stack gas moisture content have to be determined during Part 75 RM backup gas monitor test runs?

Answer: Only in certain cases. Moisture corrections will not be required if a dilution-type (wet basis) RM backup SO_2 or CO_2 pollutant monitor is used, because flow measurement is also on a wet basis, and therefore SO_2 and CO_2 mass emission rates can be calculated directly. However, if a dry-basis SO_2 or CO_2 backup RM pollutant concentration monitor is used, moisture correction will be required in order to calculate the mass emission rates.

For NO_x-diluent RM backup monitoring systems, moisture correction will be necessary only if the moisture basis of the NO_x pollutant concentration monitor is different from the moisture basis of the diluent monitor. Proper calculation of the NO_x emission rate in lb/mmBtu requires that the pollutant and diluent measurements be on a common moisture basis.

When moisture correction is necessary, unless there is a continuous moisture monitor installed on the stack (see § 75.11(b)), Reference Method 4 in Appendix A of 40 CFR 60 (or its allowable equivalents or alternatives) must be used to determine the stack gas moisture content during each backup RM monitor test run.

For sampling runs of 1 hour or less, the moisture run data must represent at least one of the 15-minute periods during which gas concentration measurements are made using RM 6C, 7E, or 3A. For runs greater than 1 hour in duration, a moisture measurement must be made during at least one 15-minute period of each clock hour of the run.

Note that EPA has authorized the use of Approximation Method 4, which is a less rigorous moisture measurement technique, for such applications (see EMTIC Guideline Document, GD-23, May 19, 1993).

References: § 75.20, § 75.22, § 75.24; 40 CFR Part 60, Appendix A

Key Words: Backup monitoring, Reference methods

History: First published in March 1995, Update #5; revised in October 1999 Revised Manual

Question 21.21 REVISED

Topic: Calculation Requiring Moisture Adjustments and RM Backup Monitoring

Question: If a primary, wet-basis SO_2 monitor is replaced by a dry-basis RM backup monitor, should the required moisture correction be applied to the reported hourly SO_2 concentration in RT 200?

Answer: No. For consistency in Part 75 reporting, the hourly SO_2 concentration obtained with the RM backup monitoring system should be reported in RT 200 on the moisture basis of the reference method monitor (in this case, on a dry basis) and the moisture correction should be applied when calculating values in the 300-level records.

The stack gas moisture content for the hour should be reported in RT 212, and the appropriate formula from RT 520 of the electronic monitoring plan should be referenced in RT 310, indicating how the moisture content, dry SO_2 concentration, and volumetric flow rate are used to calculate the SO_2 mass emission rate.

References: § 75.20, § 75.22, § 75.24

Key Words: Backup monitoring, Electronic report formats, Reference methods, Reporting

History: First published in March 1995, Update #5; revised in October 1999 Revised Manual

Question 21.22

Topic: Reporting Moisture Values and RM Backup Monitors

Question: For the wet and dry-basis primary and RM backup SO_2 monitors described in Question 21.21, does reporting SO_2 concentration data (in RT 200) on two different moisture bases affect the precision of the SO_2 missing data substitution values?

Answer: Yes, but the effect is considered to be minimal. The maximum amount of additional imprecision introduced into the 90th and 95th percentile substitution values by the occasional use of backup RM monitors is conservatively estimated to be about 1%, assuming that 10% of the "look-back" values are RM readings, and that the moisture bias of each RM data point is 10%. Recognizing that missing data values, by nature, are somewhat imprecise, this slight additional loss in accuracy is outweighed by the benefits of achieving consistency in Part 75 data reporting.

References: § 75.20, § 75.22, § 75.30

Key Words: Backup monitoring, Electronic report formats, Missing data, Reference methods, Reporting

History: First published in March 1995, Update #5

Question 21.23

Topic: Impact of RM Backup Monitor Calibration on Other Systems

Question: Suppose that an in-stack dilution probe serves several primary Part 75 analyzers (e.g., SO_2, CO_2, and NO_x). If one of the primary analyzers is replaced with a RM backup analyzer, calibration of the backup RM monitor will force the other analyzers into the calibration mode, resulting in the loss of some data from one or more of the other primary gas monitoring systems. Is this acceptable?

Answer: Yes. The RM system calibration checks are considered to be required QA/QC procedures; therefore, missing data routines will not have to be used for the other primary monitoring systems, provided that the minimum data requirements of § 75.10(d)(1) are met for each system. The data loss in successive clock hours can be minimized by initiating the RM calibration procedures during the last 15-minute period of the clock hour.

References: § 75.10(d), § 75.24

Key Words: Backup monitoring, Quality assurance, Reference methods

History: First published in March 1995, Update #5

Question 21.24 REVISED

Topic: Restrictions on Use of RM Backup Monitoring

Question: Is there any limit on the number of hours that RM backup monitoring system may be operated under Part 75?

Answer: The only restriction is that when the primary monitoring system is operating and not out-of-control, the primary system must be used for data reporting under Part 75.

References: § 75.10(e), § 75.24

Key Words: Backup monitoring, Reference methods

History: First published in March 1995, Update #5; revised in October 1999 Revised Manual

Question 21.25

Topic: Interference Check Requirements for Instrumental Methods

Question: What are the interference check requirements for instrumental reference methods in Part 75 applications?

Answer: **SO_2 Analyzers**: It is not necessary to test each individual analyzer. Rather, each SO_2 analyzer **model** must be documented to have successfully completed a 3-run interference check by comparison against: (a) a modified Method 6 train sampling at the bypass vent of the Method 6C instrumental measurement system; or (b) if a dilution probe is used, a collocated Method 6 train.

The 3-run comparison of Method 6 versus 6C is required once per source category. For Part 75 applications, source categories include: (1) uncontrolled outlets from coal or oil-fired units (or FGD inlets); (2) locations downstream of lime, limestone or other scrubbers, unless the tester can demonstrate to the satisfaction of EPA that the scrubber effluent gas stream contains no chemical species beyond those found in an uncontrolled stream that may interfere with the SO_2 measurements; (3) locations downstream of ammonia injection for NO_x control or particulate gas conditioning; and (4) any other location where the effluent is known to contain compound(s), not present in uncontrolled streams, at such levels as may interfere with the measurement principle of the analyzer.

For each of the three interference test runs, the average SO_2 concentration measured by the analyzer must agree to within 7% or 5 ppm (whichever is less restrictive) of the SO_2 concentration measured by the modified (or collocated) Method 6 train. (See also EMTIC-012, April 14, 1992, "Test Method 6C--Guidance.")

NO_x and Diluent Analyzers: Each NO_x and diluent (O_2/CO_2) RM analyzer must pass an interference response test prior to use, in accordance with § 5.4 of RM 20 (see § 6.2 of RM 7E and § 6.2 of RM 3A).

References: § 75.20, § 75.22, § 75.24; 40 CFR Part 60, Appendix A

Key Words: Backup monitoring, Quality assurance, Reference methods

History: First published in March 1995, Update #5

Question 21.26 REVISED

Topic: RM Backup Monitoring and NO_x Conversion Efficiency Tests

Question: Is a Part 75 NO_x RM backup analyzer required to pass a NO_2 to NO conversion efficiency test prior to use?

Answer: A conversion efficiency test, in accordance with § 5.6 of RM 20 or any allowable alternative, is required prior to the initial use of the NO_x analyzer as a RM backup monitor (see § 6.4 of RM 7E). This test must be repeated each time that the RM backup analyzer is brought into service and, if the analyzer is used for an extended period of time exceeding 720 hours, at least once every 720 hours that the analyzer is used.

One approved alternative procedure, described in EMTIC Guideline Document GD-030 (September 28, 1994), allows for the use of a cylinder gas containing NO_2 in nitrogen.

References: § 75.20, § 75.22, § 75.24

Key Words: Backup monitoring, Quality assurance, Reference methods

History: First published in March 1995, Update #5; revised in October 1999 Revised Manual

Question 21.27

Topic: Orsat Analysis and RM Backup Monitoring

Question: Is a validating Orsat analysis required when a diluent analyzer is used as a backup reference method monitor under Part 75?

Answer: No. Section 8 of Method 3A **recommends**, but does not require, an Orsat analysis to validate the results of each instrumental test run.

References § 75.20, § 75.22, § 75.24; 40 CFR Part 60, Appendix A

Key Words: Backup monitoring, Quality assurance, Reference methods

History: First published in March 1995, Update #5

Question 21.28 REVISED

Topic: Data Adjustments for Gas RM Backup Systems

Question: Should the raw hourly average pollutant and diluent concentrations obtained with Part 75 backup RM analyzers be reported in the 200-Level EDR records as-recorded, or do the averages first have to be adjusted in accordance with Equation 6C-1 in Reference Method 6C?

Answer: Each raw hourly average must be adjusted, using Equation 6C-1 of RM 6C before being reported in the 200-level records of the EDR. The adjustments are made by using the pre-and post-run zero and upscale system responses obtained during the bias checks (for non-dilution-type systems) or the pre- and post-run zero and upscale system responses during the system calibration error checks (for dilution systems). The same pre-and post-run quality assurance data are used to adjust each of the individual hourly average concentrations obtained during the test run.

In some instances, when dilution-type RM backup systems are used, the raw hourly averages may also need to be corrected for stack gas density effects.

(Note: For O_2 analyzers that cannot analyze zero-gas, the data are adjusted using Equation 3A-1 in RM 3A, rather than Equation 6C-1.)

References: § 75.20, § 75.22, § 75.24; EDR v2.1

Key Words: Backup monitoring, Data reduction, Reference methods

History: First published in March 1995, Update #5; revised in October 1999 Revised Manual

Question 21.29

Topic: Bias Adjustments and RM Backup Monitoring

Question: Must the data from Part 75 RM backup monitors be adjusted for bias, as described in Section 7.6.5 of Appendix A to Part 75?

Answer: No. Part 75 bias adjustments are derived from relative accuracy test data. Backup reference method analyzers are not required to undergo relative accuracy testing and therefore the data from these analyzers are not subject to the bias adjustment requirements of Section 7.6.5.

References: § 75.20, § 75.22, § 75.24; Appendix A, Section 7.6.5

Key Words: Backup monitoring, Bias, Reference methods

History: First published in March 1995, Update #5

Question 21.30 REVISED

Topic: Monitoring Plan Requirements for RM Backup Systems

Question: Is it necessary to list Part 75 backup reference method gas monitoring systems in RT 510 of the electronic monitoring plan?

Answer: Yes. All RM backup monitoring system information must be listed in RT 510, for each unit or common-stack served by the RM backup system. Each RM backup system must be assigned a unique system ID number. Each component of the monitoring system must also be assigned a unique ID number.

In column 21 of EDR RT 510, use the designation "RM" to indicate that a particular monitoring system is a reference method backup system.

All backup RM systems must include a certified Part 75 DAHS as a system component. If the reference method system has its own additional software component, this should also be listed in RT 510.

If correction for moisture is required, represent the moisture measurement component in RT 510 as part of a separate moisture monitoring system (unless a default % H_2O is used, in which case report the default moisture value in RT 531). If Reference Method 4 is used as the moisture measurement component, make the following entries in EDR RT 510: Enter "H_2O" for component type; "EXT" for the sample acquisition method; and "Method 4" for the model/version. Leave the "manufacturer" and "serial number" fields blank.

References: § 75.11(b), § 75.12, § 75.20, § 75.22, § 75.24, § 75.53

Key Words: Backup monitoring, Monitoring plan, Reference methods

History: First published in March 1995, Update #5; revised in October 1999 Revised Manual

Question 21.31 REVISED

Topic: RT 520 Formulas and RM Backup Monitoring

Question: Should backup reference method gas monitoring systems be represented in the formulas in RT 520 of the electronic monitoring plan?

Answer: Yes. For RM backup monitoring systems, sufficient formulas must be included in the monitoring plan to represent the calculation of all required quantities (i.e., SO_2 and CO_2 mass emission rates, NO_x emissions in lb/mmBtu, and heat input rate in mmBtu/hr) when the backup RM systems are used for Part 75 data reporting. Each formula must be assigned a unique identification number.

Note that redundant formulas for the RM backup monitors are unnecessary if the RM backup systems use the same basic equations as the primary monitoring systems (see EDR v2.1 Reporting Instructions for RT 520).

References: § 75.20, § 75.22, § 75.24, § 75.53

Key Words: Backup monitoring, Monitoring plan, Reference methods

History: First published in March 1995, Update #5; revised in October 1999 Revised Manual

Question 21.32 REVISED

Topic: Submission of Revised Monitoring Plans Containing RM Backup Systems

Question: When must a utility identify RM backup systems in a monitoring plan?

Answer: At the time of submittal of the monitoring plan, if possible. However, if specific RM backup system information is not known at the time of submittal of the original monitoring plan because some or all of the RM system components will be brought in from various sources on an as-needed basis, **or** if the decision to use RM backup monitors is made subsequent to submittal of the original monitoring plan, an update to RTs 510 and 520 must be submitted along with the quarterly report each time that a new RM system (i.e., one not previously used to collect data from a particular unit or stack) is used. In addition to submitting monitoring plans in the quarterly reports, the Agency is developing a procedure that will allow sources to submit monitoring plans electronically outside of the quarterly report.

References: § 75.20, § 75.22, § 75.24, § 75.53; EDR v2.1

Key Words: Backup monitoring, Monitoring plan, Reference methods

History: First published in March 1995, Update #5; revised in October 1999 Revised Manual

Question 21.33 REVISED

Topic: DAHS Verification for RM Backup Formulas

Question: For formulas in EDR RT 520 which include signals from RM backup monitoring systems, is formula verification required?

Answer: No. However, EPA will independently verify that the hourly emission rates and heat input values are properly calculated for those hours in which RM backup analyzers are used.

References: § 75.20, § 75.22, § 75.24, § 75.53

Key Words: Backup monitoring, DAHS, Reference methods

History: First published in March 1995, Update #5; revised in October 1999 Revised Manual

Question 21.34 **REVISED**

Topic: Reporting of RM Backup Data

Question: When Part 75 backup reference method gas monitoring systems are used during a calendar quarter, how are the RM data to be represented electronically in the quarterly report?

Answer: Data generated by backup RM gas monitors must be reported as hourly averages, using the usual EDR RTs for gas monitoring systems (i.e., RTs 200, 201, 202, 210, 211, and 212, as applicable). In addition, the backup reference method data (on an hourly basis) and quality assurance information (on a run basis) must be summarized using electronic RTs 260 and 261. RTs 260 and 261 are defined in EDR v2.1.

Specifically:

(1) For each hour during which pollutant or diluent concentration data are generated by a RM backup analyzer, submit one RT 200, 201, 202, 210, or 211 (whichever is applicable) and one RT 212 (if applicable).

(2) For **each hour of each RM test run**, submit one RT 260. If a NO_x/diluent RM backup system is used, separate 260 records are required for the NO_x and diluent hourly concentrations.

(3) For **each RM test run**, submit one RT 261. For NO_x/diluent RM backup systems, this will require separate RTs 261 for the NO_x and diluent QA information.

(4) If the same RM backup analyzer serves as the CO_2 pollutant concentration monitor and as the diluent monitor in the NO_x system, duplicate RTs 260 and 261, with different system ID numbers, must be submitted for CO_2.

References: § 75.20, § 75.22, § 75.24, § 75.64

Key Words: Backup monitoring, Electronic report formats, Reference methods, Reporting

History: First published in March 1995, Update #5; revised in October 1999 Revised Manual

Question 21.35 REVISED

Topic: Reporting of RM Backup Data

Question: Are there any special instructions for proper completion of the 200-level and 300-level EDR records when RM backup monitoring systems are used for Part 75 data reporting?

Answer: Yes. Use the following guidelines to ensure that the RM data are properly reported:

(1) In RTs 200, 201, 202, 210, and 211 the reported "average pollutant or diluent concentration for the hour" must be the same as the **final, adjusted** hourly average concentration from RT 260. The final, adjusted concentration is the value obtained by correcting the raw RM hourly average for calibration bias/error using Equation 6C-1 of RM 6C (or Eq. 3A-1 of RM 3A, if applicable) and for stack gas density effects, if applicable. In RT 200, record the final adjusted SO_2 concentration in column 35. Leave column 29 blank. Report the concentration values on the <u>same</u> moisture basis as the reference method raw data; do <u>not</u> correct the reported values for moisture (see Question 21.21).

(2) In RTs 200, 201, 202, 320, and 330, use a Method of Determination Code of "**04**" for each hour in which pollutant or diluent concentration data are obtained with a RM backup system.

(3) In Record Types 200, 201, 202, 210, 211, and 320, the component IDs and monitoring system IDs must refer to RM backup monitoring systems and components in RT 510 of the electronic monitoring plan.

(4) In RTs 310, 320, and 330, the formula ID must refer to the formula from RT 520 of the electronic monitoring plan that was used to calculate the emission rates.

(5) In RTs 260 and 261, report the system and component ID numbers for the appropriate RM backup monitoring system, as represented in RT 510.

(6) In RT 320, report the NO_x emission rate (calculated from the RM backup system NO_x and diluent data) in the field for adjusted average emission rate. Leave the field for unadjusted NO_x emission rate blank.

References: § 75.20, § 75.22, § 75.24, § 75.57, § 75.64

Key Words: Backup monitoring, Electronic report formats, Reference methods, Reporting

History: First published in March 1995, Update #5; revised in October 1999 Revised Manual

Question 21.36 REVISED

Topic: Recordkeeping Requirements for RM Backup Monitoring

Question: When Part 75 reference method backup monitoring systems are used during a calendar quarter, what records must be kept in addition to the information reported electronically to EPA in the quarterly report?

Answer: In addition to the electronic reporting requirements outlined in Questions 21.34 and 21.35, above, the following records must be kept on-file (active for 3 years, except for Items (6), (7), and (8), which must be kept on file permanently), to be made available to EPA upon request:

(1) The hourly average readings for each RM monitor test run, including dates and clock hours. Include both the unadjusted averages and the averages after adjustment using Equation 6C-1 of RM 6C (or Equation 3A-1 of RM 3A, if applicable) and adjustment for stack gas density effects, if applicable.

(2) The field data for all of the required RM analyzer QA/QC activities during each run (including, as applicable, calibration error checks, bias checks, zero and calibration drift checks).

(3) The field data and calculated results for any stack gas moisture content determinations made during the RM test runs.

(4) Documentation of the calibration gas concentrations used for the analyzer QA/QC activities.

(5) Documented results of the most recent NO_2 to NO conversion efficiency test of each NO_x analyzer.

(6) Documentation of the required interference check of each analyzer or analyzer model (as applicable).

(7) Field data and calculated results for any measurements that were made to verify the representativeness of the RM sampling point location (see Question 21.16).

(8) The method used (if applicable) to correct for stack gas density effects, including documentation that the method was approved by the Administrator.

References: § 75.20, § 75.22, § 75.24, § 75.57, § 75.59

Key Words: Backup monitoring, Recordkeeping, Reference methods

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Question 21.37 REVISED

Topic: Use of EPA Reference Methods for Monitoring Flow Rate

Question: May EPA Reference Methods 2, 2F, 2G, and 2H be used to provide backup data for Part 75 reporting when the primary flow monitor malfunctions?

Answer: Yes. This option is allowable under § 75.24(c)(2). However, if these methods are used, sufficient RM data must be collected to represent each unit operating hour. Therefore, use the following guidelines to collect RM backup flowrate data for Part 75:

(1) The number and location of the RM traverse points must be in accordance with EPA Reference Method 1.

(2) The proper RM run length in all cases is one hour.

(3) Each 1-hour run shall consist of a minimum of **two** complete velocity traverses. The traverses must generate sufficient data to represent at least **two** of the four 15-minute quadrants in the clock hour. Successive traverses may not begin within the same 15-minute quadrant.

(4) The individual velocity head measurements should be made at evenly-spaced time intervals over the duration of each traverse.

(5) The dry-basis CO_2 and O_2 concentrations must be accounted for to determine the dry stack gas molecular weight. These concentrations may be obtained by RM 3 or 3A, or from available CEMS data. The tester may opt to use a single CO_2 and O_2 determination for a series of flow test runs at steady process operating conditions.

(6) The moisture content of the stack gas must be accounted for, in order to calculate the wet-basis stack gas molecular weight. It is flow test run, because the calculated flow rate is relatively unaffected by minor variations in the stack gas molecular weight. The tester may therefore opt to make a single moisture determination to represent a series of flow test runs.

(7) For each clock hour, report the arithmetic average of the calculated flow rates from all traverses performed during the hour.

References: § 75.20, § 75.22, § 75.24

Key Words: Backup monitoring, Flow monitoring, Reference methods

History: First published in March 1995, Update #5; revised in October 1999 Revised Manual

Question 21.38 REVISED

Topic: Monitoring Plan Requirements for RM 2 Backup Monitoring

Question: What are the requirements for representing Reference Method 2 backup monitoring systems in RTs 510 and 520 of the electronic monitoring plan?

Answer: Create a system in RT 510, consisting of two components--the velocity probe (e.g.,Type-S pitot tube, 3-D probe) and the DAHS. Use the following guidelines for the velocity probe component when filling in RT 510:

Columns 17 and 23:	Enter "FLOW"
Column 21:	Enter "RM"
Column 27:	Enter "DP"
Column 30:	Leave blank unless probe manufacturer is known
Column 55:	Leave blank unless probe has a known model number
Column 70:	Report the identification number engraved on the probe

No formulas associated with calculations for backup flow RM monitoring systems need to be shown in RT 520 of the monitoring plan. EPA will independently verify that the volumetric flow rate was properly determined, by using the run data reported in RT 262 (see also Question 21.39).

References: § 75.20, § 75.22, § 75.24, § 75.53

Key Words: Backup monitoring, Flow monitoring, Monitoring plan, Reference methods

History: First published in March 1995, Update #5; revised in October 1999 Revised Manual

Question 21.39 REVISED

Topic: Reporting of Flow Rate from RM Backup Monitors

Question: When References Method 2, 2F, 2G, and 2H are used to generate backup flow rate data for Part 75, how are the RM data to be reported electronically in the quarterly report?

Answer: The following electronic reporting guidelines should be followed:

(1) The flow rate data must be reported in units of wet, standard cubic feet per hour (scfh) in the usual RT 220 for volumetric flow data. Use a Method of Determination Code of 04 (Reference Method).

(2) Report flow rate in column 39, the field for adjusted volumetric flow rate. Leave the field for unadjusted flow rate, beginning at column 29, blank.

(3) For **each hour** in which a RM backup flow monitor is used, submit a RT 262, summarizing the RM data and associated measurements.

References: § 75.20, § 75.22, § 75.24, § 75.64

Key Words: Backup monitoring, Electronic report formats, Flow monitoring, Reference methods, Reporting

History: First published in March 1995, Update #5; revised in October 1999 Revised Manual

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SECTION 22
SUBTRACTIVE CONFIGURATIONS

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BACKGROUND

For the Acid Rain Program (40 CFR Parts 72 through 78), SO_2 and heat input (HI) monitoring requirements for exhaust configurations in which units discharge to the atmosphere through a common stack are defined in § 75.16. For a State or Federal NO_x mass emissions reduction program subject to Subpart H of 40 CFR 75, provisions for monitoring various common stack configurations are found in § 75.72. For units subject to the OTC NO_x Budget Program, the document entitled, "Guidance for Implementation of Emission Monitoring Requirements for the NO_x Budget Program" (January 28, 1997), contains provisions for determining NO_x mass emissions in common stack configurations. In the specific case where affected and nonaffected units share a common stack, the allowable monitoring options under all of these programs are similar. To determine emissions for the affected units, you may:

(1) Monitor in the duct(s) leading from the affected unit(s) to the common stack; or

(2) Monitor at the common stack and opt-in the nonaffected units; or

(3) Monitor at the common stack and attribute all of the emissions to the affected units; or

(4) Petition EPA to use an alternative approach; or

(5) Monitor the combined emissions from the affected and nonaffected units at the common stack and monitor the emissions of each nonaffected unit in the duct from the nonaffected unit to the common stack, and then determine the affected unit emissions by subtraction. Questions 22.1 through 22.12 provide monitoring and reporting guidelines for this subtractive stack configuration.

(Note: Common stack NO_x *emission rate* monitoring and reporting is not addressed in this section. For information about NO_x emission rate monitoring for affected units and nonaffected units sharing a common stack, consult Section 24 of this Policy Manual.)

DEFINITIONS

Affected Unit: A unit subject to an SO_2 or NO_x mass emissions limitation under the Acid Rain Program or under a State or Federal NO_x mass trading program.

Main Common Stack: The stack through which the emissions from all units (affected and nonaffected) in a subtractive stack configuration discharge to the atmosphere.

Nonaffected Unit: A unit not subject to an SO_2 or NO_x mass emissions limitation under the Acid Rain Program or under a State or Federal NO_x mass trading program.

Secondary Common Stack: A location in the ductwork of a subtractive stack configuration, upstream of the main common stack, where the combined emissions from two or more nonaffected units are monitored.

Subtractive Stack Configuration: An exhaust configuration in which combined emissions from affected and nonaffected units discharge to the atmosphere through a common stack, and for which the mass emissions and heat input from the affected unit(s) are determined by subtracting the mass emissions and heat input measured at the nonaffected unit(s) from the combined mass emissions and heat input measured at the common stack.

Question 22.1

Topic: Purpose of Subtractive Stack Policy

Question: What is the purpose of this policy?

Answer: If you have an exhaust configuration consisting of affected and nonaffected units that discharge to the atmosphere through a common stack and you elect to use the subtractive stack methodology (i.e., option 5 under Background section, above), this policy provides guidance on emissions monitoring and reporting.

You may use this guidance under § 75.16(b)(2)(ii)(A) without approval of a petition for SO_2 mass emissions determinations under the Acid Rain Program. However, for NO_x mass emissions applications under the OTC NO_x Budget Program you must petition the permitting authority and under Subpart H of 40 CFR Part 75, you must petition the Administrator and the permitting authority for permission to use a subtractive stack methodology (see § 75.72(b)(2)(ii)). If your petition is consistent with the provisions of this policy, you have reasonable assurance that the petition will be approved and your monitoring will be consistent with other facilities using a subtractive stack methodology.

References: § 75.16, § 75.72(b)(2)(ii)

Key Words: NO_x monitoring

History: First published in March 2000, Update #12

Question 22.2

Topic: Monitoring Requirements for SO_2 and Heat Input Rate

Question: What are the SO_2 mass emission rate and heat input rate monitoring requirements for Acid Rain Program affected units that are in a subtractive stack configuration?

Answer: Sections 75.16(b)(2)(ii)(B) and 75.16(e) of Part 75 specify the SO_2 mass emission rate and heat input rate monitoring requirements for the common stack and for the nonaffected units in a subtractive stack configuration. These rule provisions are summarized in Sections A, B, and C, below. The hourly SO_2 mass emission rates and heat input rates described in sections A, B and C are calculated using the applicable equations from Appendix F or Appendix D to Part 75:

A. Main Common Stack Hourly SO_2 and Heat Input Rate Monitoring Requirements

The owner or operator of an Acid Rain-affected facility with a subtractive stack configuration must monitor hourly SO_2 mass emission rate and heat input rate at the common stack using the following methodologies:

(1) For SO_2 mass emission rate: an SO_2 CEM and a flow monitor; and

(2) For heat input rate: a stack flow monitor and a diluent gas (CO_2 or O_2) monitor.

B. Nonaffected Unit(s) Hourly SO_2 Monitoring Requirements

The owner or operator must determine the hourly SO_2 mass emission rate (in lb/hr) at the nonaffected unit(s) using one of the methodologies below:

(1) Install an SO_2 CEM and a flow monitor in the duct from each nonaffected unit to the common stack; or

(2) If the emissions from two or more nonaffected units in the subtractive stack configuration are combined prior to discharging through the main common stack, you may monitor the combined nonaffected unit SO_2 emissions at a single location, defined as a second common stack, in lieu of installing separate CEMS on each unit; or

(3) For nonaffected gas or oil-fired units, you may use Appendix D SO_2 mass emission rate estimation procedures based on fuel flow rate measurements and fuel sampling.

C. Nonaffected Unit(s) Hourly Heat Input Rate Monitoring Requirements

The owner or operator must determine the hourly heat input rate at each nonaffected unit using one of the following methodologies:

(1) You may install a flow monitor and a diluent gas monitor in the duct from each nonaffected unit to the common stack; or

(2) If the flue gases from two or more nonaffected units in the subtractive stack configuration are combined prior to discharging through the main common stack, you may monitor the combined heat input rate at a single location (designated as a secondary common stack) in lieu of separately monitoring

each unit. If this alternative is chosen, you must apportion the heat input rate measured at the secondary common stack to the individual nonaffected units; or

(3) In lieu of directly monitoring the heat input rate(s) of the nonaffected unit(s), you may opt to monitor heat input rate at the main common stack, only. This option is only allowed if all of the units exhausting to the common stack:

(i) Combust the same type of fuel; and

(ii) Use the same F factor.

Note that when this option is selected, the heat input rate measured at the main common stack is a *combined* rate, representing both the affected and nonaffected units. Therefore, you must apportion the main common stack heat input rate to all of the units (affected and nonaffected) in the subtractive stack configuration; or

(4) For nonaffected gas and oil-fired units, you may use Appendix D heat input rate estimation procedures based on fuel flow rate measurements and fuel sampling.

(Note: For a common pipe configuration, you must apportion the heat input rate measured at the common pipe to the individual nonaffected units.)

See Question 22.4 for a more detailed discussion of heat input rate apportionment in subtractive stack configurations.

D. Affected Unit(s) Hourly SO_2 Monitoring Requirements

Use Equation SS-1a (see Table 22-1) to determine the total hourly SO_2 mass emissions (in lb) for the affected unit(s) by subtraction. In Equation SS-1a, use the measured SO_2 mass emission rates from Sections A and B, above, along with the unit and stack operating times. When the combined emissions from two or more nonaffected units are monitored at a single location, then, for those units, replace the term $SO2_{nonaff}\, t_{nonaff}$ in Equation SS-1a with the term $SO2_{CS*}\, t_{CS*}$, where $SO2_{CS*}$ is the combined SO_2 emission rate for the nonaffected units and t_{CS*} is the stack operating time at the monitored location (which is designated as a secondary common stack).

If any of the nonaffected units are oil or gas-fired and receive fuel from a common pipe, then, for those units, replace the expression $SO2_{nonaff}\, t_{nonaff}$ in Equation SS-1a with the expression $SO2_{CP}\, t_f$, where $SO2_{CP}$ is the measured hourly SO_2 mass emission rate at the common pipe and t_f is the fuel usage time at the common pipe.

After determining the total hourly SO_2 mass emissions for the affected units, use Equation SS-1b (see Table 22-1) to apportion the total hourly SO_2 mass emissions to the individual affected units.

Ensure that Equations SS-1a and SS-1b (as applicable) are implemented on an hourly basis in the data acquisition and handling system (DAHS), so that the cumulative SO_2 mass emissions reported are correct. Keep records of all hourly SO_2 mass emissions values for the affected units and use these values to calculate the quarterly and cumulative SO_2 mass emissions (in tons) from the affected units. However, do not report any SO_2 mass emission rates (in lb/hr) or SO_2 mass emissions (in lb) in RTs 310 for the affected units.

Table 22-1: Hourly So_2 Mass Emissions Formulas for the Affected Unit(s)

Equation Code	Formula	Where
SS-1a	$SO2\,M_{aff-tot} = SO2_{CS}\,t_{CS} - \sum_{All-nonaff} SO2_{nonaff}\,t_{nonaff}$	$SO2M_{aff\text{-}tot}$ = Total hourly SO_2 mass emissions from the affected unit(s) (lb) $SO2_{CS}$ = Hourly SO_2 mass emission rate measured at the common stack (lb/hr) $SO2_{nonaff}$ = Hourly SO_2 mass emission rate measured at a particular nonaffected unit (lb/hr) t_{CS} = Operating time for the common stack (hr) t_{nonaff} = Operating time for a particular nonaffected unit (hr)
SS-1b	$SO2\,M_{aff-i} = SO2\,M_{aff-tot}\,\frac{L_{aff-i}t_{aff-i}}{\sum_{all-aff} L_{aff-i}t_{aff-i}}$	$SO2M_{aff\text{-}i}$ = Hourly SO_2 mass emissions from a particular affected unit (lb) $SO2M_{aff\text{-}tot}$ = Total hourly SO_2 mass emissions from the affected unit(s) (lb) $(L)_{aff\text{-}i}$ = Hourly unit load for a particular affected unit (MW or klb per hour of steam) $t_{aff\text{-}i}$ = Operating time for a particular affected unit (hr)

When using Equation SS-1a, if in a given hour the measured total SO_2 mass emissions (in lb) at the nonaffected units are greater than the mass emissions measured at the main common stack (i.e., if the summation term to the right of the minus sign in Equation SS-1a is greater than the term to the left of the minus sign), this will result in negative mass emissions for that hour. For any hour in which this happens, substitute a value of zero for the total SO_2 mass emissions from the affected units when determining quarterly, or year-to-date SO_2 mass for the affected units.

E. Affected Unit(s) Hourly Heat Input Rate Determination

Determine the hourly heat input rate for each affected unit, using the applicable method described in Question 22.4.

F. Affected Unit(s) Hourly Load and Operating Time

As indicated in paragraphs A through D, above, emissions from the affected units in a subtractive stack configuration are not measured directly. However, the owner or operator must maintain hourly records of unit load and unit operating time for each affected unit, for the purposes of apportioning emissions and/ or heat input to the individual affected units. Report these hourly values in RT 300.

References: § 75.16(b)(2)(ii)(B), § 75.16(e)

Key Words: SO_2 monitoring, Heat input

History: First published in March 2000, Update #12

Question 22.3

Topic: Monitoring Requirements for NO_x Mass

Question: What are the NO_x mass emissions monitoring requirements for subtractive stack configurations under Subpart H of 40 CFR Part 75 or under the OTC NO_x Budget Program?

Answer: The monitoring requirements for the common stack and for the nonaffected units in the subtractive stack configuration are found in § 75.72(b)(2) and on pages 14 and 15 of the "Guidance for Implementation of Emission Monitoring Requirements for the NO_x Budget Program" (dated January 28, 1997). These provisions are summarized in Sections A and B, below. The hourly NO_x emission rates, NO_x mass emissions, and heat input rates described in Sections A and B are calculated using the applicable equations from Appendix F or Appendix D to Part 75:

A. Main Common Stack NO_x Monitoring Requirements

The owner or operator must determine NO_x mass emissions at the common stack using either a "NO_x emission rate and heat input rate" methodology or a "NO_x concentration and stack flow rate" methodology, as follows:

(1) You may install a NO_x-diluent CEMS for NO_x emission rate determination and a stack flow monitor and a diluent monitor for heat input rate determination; or

(2) You may install a NO_x concentration CEM and a stack flow monitor; or

(3) If the subtractive stack configuration consists exclusively of oil and gas-fired units exhausting to a common stack, you may install a NO_x-diluent CEM at the main common stack to determine the NO_x emission rate, use Appendix D fuel flowmeters to determine unit-level heat input rates, and then derive the heat input rate at the common stack from the unit-level heat input rates and operating times, using Equation F-25 in Appendix F of Part 75 (see heat input apportionment and summation formula Table under Question 22.4, below).

B. Nonaffected Unit(s) Hourly NO_x Monitoring Requirements

The owner or operator must determine hourly NO_x mass emissions at the nonaffected unit(s) using one of the following methodologies:

(1) Install a NO_x-diluent CEMS, a stack flow monitor, and a diluent monitor in the duct leading from each nonaffected unit to the common stack; or

(2) If the emissions from two or more nonaffected units in the subtractive stack configuration are combined prior to discharging through the main common stack, you may monitor the combined nonaffected unit NO_x emission rate and heat input rate at a single location in lieu of installing separate CEMS on each unit. Define the monitoring location as a secondary common stack serving the nonaffected units; or

(3) If the following conditions are met:

(i) All units (affected and nonaffected) exhausting to the main common stack combust the same type of fuel and use the same F factor; and

(ii) All units (affected and nonaffected) exhausting to the main common stack are of the same basic design with a similar combustion efficiency (±10%); and

(iii) There is no suitable location in the existing ductwork at which to install a flow monitor, then it is not necessary to monitor heat input rate at the nonaffected units (see § 75.72(g)). Therefore, when the conditions above are met, you may opt to install NO_x-diluent monitoring systems on the nonaffected units (or group(s) of units) and monitor heat input rate only at the main common stack.

Paragraph A in Question 22.4 explains how to determine the nonaffected unit heat input rates when heat input rate is monitored only at the main common stack; or

(4) You may install a NO_x concentration CEM and flow monitor in the duct from each nonaffected unit to the common stack; or

(5) If the emissions from two or more nonaffected units in the subtractive stack configuration are combined prior to discharging through the main common stack, you may monitor the combined nonaffected unit NO_x concentration and flow rate at a single location in lieu of installing separate CEMS on each unit. Define the monitoring location as a secondary common stack serving the nonaffected units; or

(6) For nonaffected oil or gas-fired units, you may install a NO_x-diluent CEMS in the duct from each nonaffected unit to the common stack, and use Appendix D fuel flowmeter(s) to determine the unit heat input rate(s).

(Note: If any of the nonaffected units receive fuel through a common pipe, you must apportion the heat input rate measured at the common pipe to the individual units (see Question 22.4)); or

(7) If the emissions from two or more nonaffected oil and gas-fired units in the subtractive stack configuration are combined prior to discharging through the main common stack, you may monitor the combined nonaffected unit NO_x emissions at a single location in lieu of installing separate NO_x-diluent CEMS on each unit. Define the monitoring location as a secondary common stack serving the nonaffected units. Determine the heat input rate at the secondary common stack by summing the unit-level heat inputs, using Equation F-25 in Appendix F of Part 75 (see heat input rate apportionment and summation formula Table in Question 22.4, below).

C. Affected Unit(s) Hourly NO_x Mass Emissions Determination

Determine the total hourly NO_x mass emissions (in lb) for the affected unit(s), by substituting the measured NO_x mass emissions from Sections A and B, above into Equation SS-2a (see Table 22-2). Then, use Equation SS-2b or SS-2c (as applicable) (see Table 22-2) to apportion the total hourly NO_x mass emissions to the individual affected units. Equation SS-2b applies when unit load is reported in megawatts. Equation SS-2c applies when unit load is reported in klb of steam per hour. Note that the summation terms in the denominators of these equations include only the heat input rates and load values for the *affected* units.

Ensure that Equations SS-2a, SS-2b, and SS-2c (as applicable) are implemented on an hourly basis in the data acquisition and handling system (DAHS), so that the NO_x mass emissions reported are correct. Keep records of all hourly NO_x mass emissions values for the affected units, as determined from these equations, and use the hourly values to calculate the quarterly and cumulative NO_x mass emissions (in tons) for these units. However, do not report any hourly NO_x mass emissions values in RT 328 for the affected units.

When using Equation SS-2a , if in a given hour the measured total NO_x mass emissions (lb) at the nonaffected units are greater than the mass emissions measured at the common stack (i.e., if the summation term to the right of the minus sign in Equation SS-2a is greater than the term to the left of the minus sign), this will result in negative mass emissions for that hour. For any hour in which this happens, substitute a value of zero for the total NO_x mass emissions from the affected units.

Table 22-2: Hourly NO_x Mass Emissions for the Affected Unit(s)

Equation Code	Formula	Where
SS-2a	$NOXM_{aff-tot} = NOXM_{CS} - \sum_{all-nonaff} NOXM_{nonaff}$	$NOXM_{aff\text{-}tot}$ = Total hourly NO_x mass emissions from the affected unit(s) (lb) $NOXM_{CS}$ = Hourly NO_x mass measured at the common stack (lb) $NOXM_{nonaff}$ = Hourly NO_x mass measured at a particular nonaffected unit (lb)
SS-2b	$NOXM_{aff-i} = NOXM_{aff-tot} \dfrac{MW_{aff-i} t_{aff-i}}{\sum_{all-aff} MW_{aff-i} t_{aff-i}}$	$NOXM_{aff\text{-}i}$ = Hourly NO_x mass emissions from a particular affected unit (lb) $NOXM_{aff\text{-}tot}$ = Total hourly NO_x mass emissions from the affected unit(s) (lb) $(MW)_{aff\text{-}i}$ = Hourly load for a particular affected unit (MW) $t_{aff\text{-}i}$ = Operating time for a particular affected unit (hr)
SS-2c	$NOXM_{aff-i} = NOXM_{aff-tot} \dfrac{ST_{aff-i} t_{aff-i}}{\sum_{all-aff} ST_{aff-i} t_{aff-i}}$	$NOXM_{aff\text{-}i}$ = Hourly NO_x mass emissions from a particular affected unit (lb) $NOXM_{aff\text{-}tot}$ = Total hourly NO_x mass emissions from the affected unit(s) (lb) $(ST)_{aff\text{-}i}$ = Hourly load for a particular affected unit (klb/hr of steam) $t_{aff\text{-}i}$ = Operating time for a particular affected unit (hr)

D. Affected Unit(s) Hourly Heat Input Rate Determination

Determine the hourly heat input rate for each affected unit using the applicable method described under Question 22.4.

E. Affected Unit Hourly Load and Operating Time

As indicated in Sections A through C, above, emissions from the affected units in a subtractive stack configuration are not measured directly. However, the owner or operator must maintain hourly records of unit load and unit operating time for each affected unit, for purposes of apportioning emissions and/or heat input to the individual affected units. Report these hourly values in RT 300.

References: § 75.72(b)(2)

Key Words: Flow monitoring, Heat input, NO_x monitoring

History: First published in March 2000, Update #12

Question 22.4

Topic: Reporting of Hourly Heat Input Rate

Question: How do I determine and report hourly heat input rates for a subtractive stack configuration?

Answer: Except for the circumstances described in the Notes at the end of this question, determine hourly heat input rates: (1) at the main common stack; (2) at any secondary common stack(s); (3) any common pipe(s) and (4) for each individual unit in the subtractive stack configuration (both affected and nonaffected units). Report the required heat input rate values in column 36 of RT 300. Determine the hourly heat input rates as follows:

A. Heat Input Rate Measured at the Main Common Stack Only

When heat input rate is measured only at the main common stack (for qualifying configurations, as described in Section C.(3) of Policy Question 22.2 or in Section B.(3) of Policy Question 22.3), apportion the hourly heat input rate at the common stack to each of the units in the subtractive stack configuration (both affected and nonaffected units) using Equation F-21a or F-21b in Appendix F to Part 75 (see Table 22-3), for each stack operating hour (each hour in which effluent gases discharge through the main common stack). The summation term in the denominator of these equations must include all unit loads (for both the affected and non-affected units).

Table 22-3: Hourly Heat Input Rate Apportionment and Summation Formulas

Equation Code	Formula	Where
F-21a	$$HI_i = HI_{CS} \left(\frac{t_{CS}}{t_i} \right) \left[\frac{MW_i \; t_i}{\sum_{i=1}^{n} MW_i \; t_i} \right]$$	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 for a unit (MWe) t_i = Operating time at a particular unit (hour or fraction of an hour) t_{CS} = Operating time at common stack (hour or fraction of an hour) n = Total number of units using the common stack or pipe i = Designation of a particular unit
F-21b	$$HI_i = HI_{CS} \left(\frac{t_{CS}}{t_i} \right) \left[\frac{SF_i \; t_i}{\sum_{i=1}^{n} SF_i \; t_i} \right]$$	HI_i = Heat input rate for a unit (mmBtu/hr) HI_{CS} = Heat input rate at the common stack or pipe (mmBtu/hr) SF_i = Gross steam load for a unit (klb/hr) t_i = Operating time at a particular unit (hour or fraction of an hour) t_{CS} = Operating time at common stack (hour or fraction of an hour) n = Total number of units using the common stack or pipe i = Designation of a particular unit
F-25	$$HI_{CS} = \frac{\sum_{all-units} HI_u t_u}{t_{CS}}$$	HI_{CS} = Heat input rate at the common stack (mmBtu/hr) I_u = Heat input rate for a unit (mmBtu/hr) t_u = Operating time at a particular unit (hour or fraction of an hour) t_{CS} = Operating time at common stack (hour or fraction of an hour)

B. Heat Input Rate Measured at the Main Common Stack and the Nonaffected Unit(s)

When heat input rate is monitored or measured at both the main common stack and at the nonaffected unit(s), determine the heat input rate for each unit in the subtractive stack configuration as follows:

Scenario #1. For hours in which <u>both</u> affected and nonaffected units are operating and the total heat input in mmBtu measured at the main common stack is greater than the total heat input of the nonaffected unit(s):

(i) For the affected units:

(A) Use Equation SS-3a (see Table 22-4) to obtain the total hourly heat input for the affected units. The term on the left side of the minus sign in Equation SS-3a is the hourly total heat input at the main common stack (mmBtu), and is the product of the measured heat input rate in column 36 of RT 300 and the stack operating time in column 18 of RT 300. The term on the right hand side of the minus sign is the total hourly heat input for the nonaffected units, and is the sum of the products of the measured RT 300/36 heat input rates and the RT 300/18 unit operating times for all of the nonaffected units.

(B) If any nonaffected units are monitored as a group at a single location, then, for those units, replace the term $HI_{nonaff}\ t_{nonaff}$ in Equation SS-3a with the term $HI_{CS*}\ t_{CS*}$, where HI_{CS*} is the hourly heat input rate measured at the nonaffected units' monitoring location (designated as a secondary common stack) and t_{CS*} is the stack operating time at the secondary common stack.

(C) For each hour in which Scenario # 1 applies, calculate the individual affected unit heat rates using Equation SS-3b (see Table 22-4). Note that the summation term in the denominator of Equation SS-3b includes only the affected unit hourly loads.

(ii) For the nonaffected units:

(A) If the nonaffected units are individually monitored for heat input rate, report the measured hourly heat input rate value(s). This includes gas and oil-fired units using Appendix D procedures to determine heat input rate.

(B) If, for a group of nonaffected units, heat input rate is monitored at a single location (designated as a secondary common stack) using a flow monitor and a diluent CEM, apportion the heat input rate measured at the secondary common stack to the individual nonaffected units in the group, using Equation F-21a or F-21b in Appendix F to Part 75. When this methodology is used, replace the term t_{CS} in Equation F-21a or F-21b with the term t_{CS*}, where t_{CS*} is the stack operating time at the secondary common stack. Also, include only the hourly unit loads for the nonaffected units in the summation term in the denominator of Equation F-21a or F-21b.

(C) For a group of oil or gas-fired nonaffected units that receive fuel from a common pipe, apportion the heat input rate measured at the common pipe to the individual nonaffected units, using Equation F-21a or F-21b in Appendix F to Part 75. In using these equations, replace the term

"t_{CS}" with the term "t_f", which is the fuel usage time for the common pipe.

Table 22-4: Hourly Heat Input Formulas for Affected Units

Equation Code	Formula	Where
SS-3a	$HItot_{aff-hr} = HI_{CS} t_{CS} - \sum_{all-nonaff} HI_{nonaff} t_{nonaff}$	$HItot_{aff\text{-}hr}$ = Total hourly heat input for the affected units (mmBtu) HI_{CS} = Hourly heat input rate at the common stack (mmBtu/hr) HI_{nonaff} = Hourly heat input rate for a particular nonaffected unit (mmBtu/hr) t_{CS} = Operating time for the common stack (hr) t_{nonaff} = Operating time for a particular nonaffected unit (hr)
SS-3b	$HI_{aff} = \frac{1}{t_i} \times HItot_{aff-hr} \times \left(\frac{L_i t_i}{\sum_{all-aff} L_i t_i} \right)$	HI_{aff} = Hourly heat input rate for a particular affected unit (mmBtu/hr) $HItot_{aff\text{-}hr}$ = Total hourly heat input for all affected units (mmBtu) t_i = Operating time for a particular affected unit (hr) L_i = Hourly unit load for an affected unit in the subtractive stack configuration (MW <u>or</u> klb of steam per hour)

Scenario #2. For any hour in which both nonaffected unit(s) and affected unit(s) are operating and the total heat input at the main common stack is less than or equal to the total heat input for the nonaffected unit(s), causing Equation SS-3a to give a negative or zero total heat input value for the affected units, follow these procedures:

(i) Invalidate the result obtained from Equation SS-3a; and

(ii) Consider the heat input rate measured at the main common stack to be correct; and

(iii) Disregard all heat input rate(s) measured at the nonaffected unit(s); and

(iv) Apportion the heat input rate measured at the main common stack to all units (affected and nonaffected) in the subtractive stack configuration, using Equation F-21a or F-21b.

Scenario # 3. For any hour in which <u>only</u> affected units are operating,

(i) <u>For the affected units</u>:

(A) Set the summation term in Equation SS-3a equal to zero, so that the total heat input for the affected units equals the heat input measured at the main common stack.

(B) Then, use Equation SS-3b to determine the hourly heat input rate for each affected unit.

(ii) <u>For the nonaffected units</u>:

Assign a heat input rate value of zero to each nonaffected unit.

Scenario #4. For any hour in which <u>only</u> nonaffected units are exhausting to the common stack,

(i) <u>For the affected units</u>:

Assign a heat input rate value of zero to each affected unit.

(ii) <u>For the nonaffected units</u>:

(A) Invalidate all measured heat input rates for the nonaffected units; and

(B) Consider the heat input rate measured at the main common stack to be correct; and

(C) Apportion the heat input rate measured at the main common stack to the nonaffected units, using Equation F-21a or F-21b.

<u>Notes</u>: Units affected only by a State NO_x mass program (Subpart H or OTC) may not be required to report hourly heat input rate and cumulative heat input when using a stack flow monitor and NO_x concentration CEM to determine NO_x mass emissions. Consult your State rule to determine whether you are required to monitor heat input rate when using this methodology. Units affected only by 40 CFR Part 97 (Federal NO_x Trading Program) are required to report hourly heat input rate and cumulative heat input in these circumstances.

Heat input rate monitoring may not be required if your State does not require heat input for allocation purposes. If heat input rate monitoring and cumulative heat input accounting are not required, leave the heat input field(s) blank in RTs 300 and 307.

The use of common stack heat input rate apportionment is not allowed in all situations. Consult EPA and your State rule to determine whether you are allowed to apportion heat input rate.

References: Appendix F

Key Words: Heat input

History: First published in March 2000, Update #12

Question 22.5

Topic: Monitoring Plan Requirements

Question: What are the electronic monitoring plan reporting requirements for subtractive stack configurations?

Answer: For all units in the subtractive stack configuration, including the nonaffected unit(s), report all standard unit-level monitoring plan record types including unit data, program data, monitoring methodologies, controls and fuels (i.e., RTs 504, 505, 585, 586, 587).

For the main common stack serving both affected and nonaffected units, define the relationship between the stack and units in RTs 503 and submit all the standard monitoring plan information to support the continuous emission monitoring systems (CEMS) at the common stack (RTs 510, 520, 530, 531, 535, and 536, as applicable). Report one RT 503 for each of the units served by the common stack.

If the combined emissions from a group of nonaffected units are monitored at a single location (i.e., a secondary common stack, serving only the nonaffected units), report one RT 503 for each nonaffected unit in the group that defines the relationship between the unit and the secondary common stack.

If a group of nonaffected units receives fuel from a common pipe, report one RT 503 for each unit in the group that defines the relationship between the unit and the common pipe.

For each nonaffected unit monitoring location, report all the standard monitoring plan information to support the CEMS or other monitoring systems for that location (RTs 510, 520, 530, 531, 535, 536, and 540, as applicable).

For each affected unit, report the applicable subtractive mass emissions and heat input formulas and any apportionment formulas in RTs 520 (i.e., Equations SS-1a, SS-1b, SS-2a, SS-2b, SS-2c, SS-3a, SS-3b, F-21a, F-21b, or F-25, as applicable).

If you petition and receive approval to use a minimum NO_x rate for missing data purposes, include the approved minimum rate in RT 531. Use the code "MNNX" as the parameter and "APP" (approval) as the source of data code. See Policy Question 22.10.

Also include a narrative description of the subtractive stack configuration and method used to determine NO_x mass emissions in RT 910, as described in Policy Question 22.11.

References: EDR v2.1, 500-level RTs

Key Words: Electronic report formats, Monitoring plan

History: First published in March 2000, Update #12

Question 22.6

Topic: QA Requirements

Question: What are the quality assurance requirements for the monitoring systems installed on the nonaffected unit(s) in a subtractive stack configuration?

Answer: The monitoring systems for the nonaffected unit(s) in a subtractive stack configuration must be fully certified in accordance with § 75.20 and must undergo the periodic quality assurance testing required under § 75.21 and Appendix B to Part 75. The bias test requirement in Section 7.6 of Appendix A to Part 75 also applies to the SO_2, NO_x, and flow rate monitoring systems installed on nonaffected units.

References: § 75.20, § 75.21; Appendix A, Section 7.6

Key Words: Certification tests, Quality assurance

History: First published in March 2000, Update #12

Question 22.7

Topic: Unit/Stack EDRs

Question: Should all the units and stacks involved in the subtractive configuration be included together in the same quarterly report?

Answer: Yes. Based on EPA guidance, all stack-level and associated unit-level data must be contained in a single quarterly report.

References: EDR v2.1

Key Words: Reporting

History: First published in March 2000, Update #12

Question 22.8

Topic: Reporting Hourly Emissions Data

Question: How do I report hourly emissions data for a subtractive stack configuration?

Answer: Report hourly data for the subtractive stack configuration at each monitored location (i.e., at the common stack and at each nonaffected unit monitoring location), as you would for any other configuration. Report only the measured data. Do not report the hourly mass emission values determined by subtraction for the *affected* units. If you have additional reporting questions, contact EPA.

References: § 75.64

Key Words: Reporting

History: First published in March 2000, Update #12

Question 22.9

Topic: Cumulative Emissions Data Reporting

Question: What quarterly, annual, and ozone season summary emissions and heat input data should I report for a subtractive configuration?

Answer: For each stack, pipe, or unit in the subtractive stack configuration (including both affected and nonaffected units), report a RT 301 (for units subject to the Acid Rain Program) and report a RT 307 (for units subject to Subpart H).

A. RT 301 for Acid Rain Program

Report separate RTs 301 for the main common stack, any secondary common stack(s), any common pipe(s), and for each unit in the subtractive stack configuration.

Two examples are provided for reference:

(1) If there is a main common stack, one affected unit and one nonaffected unit in the subtractive stack configuration, report three RTs 301 in each quarterly report: one for the common stack, one for the affected unit, and one for the nonaffected unit.

(2) If there is a main common stack through which four units exhaust to the atmosphere, two of which are nonaffected and two of which are affected, and if the nonaffected units are monitored at a secondary common stack location, report six RTs 301, one at the main common stack, one at the secondary common stack and one for each unit.

In the RT 301 for the main common stack, report the quarterly and year-to-date SO_2 mass emissions (tons) and heat input (mmBtu) values derived from the common stack monitors. Report the quarterly and cumulative NO_x emission rates (lb/mmBtu), as required by Part 75. Calculate all quarterly and cumulative emissions and heat input values in accordance with the applicable sections of the "EDR Version 2.1 Reporting Instructions."

In the RT 301 for a secondary common stack location at which a group of nonaffected units is monitored (if applicable), report all quarterly and cumulative SO_2 mass emissions and heat input values derived from the hourly CEMS measurements made at the monitoring location, or heat input apportioned to the secondary common stack location.

In the RT 301 for each nonaffected unit, report all required quarterly and cumulative heat input data (either measured or apportioned as appropriate). If the nonaffected unit is individually monitored for SO_2, also report quarterly and cumulative SO_2 mass emissions data. If the unit is not separately monitored, report only the quarterly and cumulative heat input information.

In the RT 301 for an affected unit, report the quarterly and cumulative heat input that was derived using one of the accepted methodologies in this policy. Also report quarterly and cumulative SO_2 mass emissions data. Use Equation SS-4 (see Table 22-5).

In the RT 301 for a common pipe, report the quarterly and cumulative heat input values derived from the hourly heat input rate measurements and fuel usage times at the common pipe. Also report the quarterly and cumulative SO_2 mass emissions derived from the fuel flowmeter readings, fuel sampling data, and fuel usage times.

(Note: The reporting of NO_x emission rate for the individual affected and nonaffected units in the subtractive stack configuration is beyond the scope of this policy. For further guidance, see Section 24.)

Table 22-5: Quarterly, Year-to-date, or Ozone Season Mass Emissions for Subtractive Stacks

Equation Code	Formula	Where
SS-4	$M_{YTD} = \frac{\sum_{i=1}^{n} M_i}{2000}$	M_{YTD} = Quarterly, ozone season or year-to-date SO_2 or NO_x mass emissions (tons) M_i = Hourly SO_2 or NO_x mass emissions value, as determined under this policy (lb) 2000 = Conversion factor from lb to tons n = Number of unit or stack operating hours in the reporting period i = Designation of a particular hour

B. RT 307 for Subpart H

Report separate RTs 307 for the main common stack, any secondary common stack(s), any common pipe(s), and each unit in the subtractive stack configuration.

Two examples are provided for reference:

(1) If there is a main common stack, one affected unit and one nonaffected unit in the subtractive stack configuration, report three RTs 307 in each quarterly report: one for the common stack, one for the affected unit, and one for the nonaffected unit.

(2) If there is a main common stack through which four units exhaust to the atmosphere, two of which are nonaffected and two of which are affected, and if the nonaffected units are monitored at a secondary common stack location, report six RTs 307, one at the main common stack, one at the secondary common stack and one for each unit.

In the RT 307 for the main common stack, report the quarterly and cumulative NO_x mass emissions and heat input values derived from the common stack monitors. Calculate the quarterly and cumulative NO_x mass emissions according to the applicable sections of the "EDR Version 2.1 Reporting Instructions."

In the RT 307 for a secondary common stack location at which a group of nonaffected units is monitored (if applicable), report all quarterly and cumulative NO_x mass emissions and heat input values derived from the hourly CEMS or corresponding fuel flowmeter measurements made at the monitoring location.

In the RT 307 for a nonaffected unit, report any required heat input data (derived either from measured or apportioned heat input rates, as appropriate). If the unit is individually monitored for NO_x, also report quarterly and cumulative NO_x mass emissions data.

In the RT 307 for an affected unit, report the quarterly and cumulative heat input derived using one of the accepted methodologies in this policy. Also report quarterly and cumulative NO_x mass emissions data. Calculate the quarterly and cumulative NO_x mass emissions for the affected unit using Equation SS-4 (see Table 22-5).

In the RT 307 for a common pipe, report the quarterly and cumulative heat input values derived from the hourly heat input rate measurements and fuel usage times at the common pipe.

References: EDR v2.1, RT 301, RT 307

Key Words: Electronic report formats

History: First published in March 2000, Update #12

Question 22.10

Topic: Missing Data Requirements

Question: What missing data requirements apply to nonaffected units in a subtractive stack configuration?

Answer: For the common stack, use the standard missing data procedures in § 75.33.

For the nonaffected unit(s), use inverse missing data procedures for SO_2, NO_x, CO_2 and flow rate missing data (i.e., substitute the 10th percentile value when the standard missing data procedures in § 75.33 require the 90th percentile value, use the 5th percentile value in lieu of the 95th percentile value, use the minimum value in the look back periods instead of the maximum value, and use zeros for the minimum potential NO_x emission rate, minimum potential flow rate or minimum potential concentration for any hours in which maximum potential values would ordinarily be used under Subpart D of Part 75). The owner or operator may petition the Administrator under § 75.66 to use minimum potential values other than zero.

If O_2 data, rather than CO_2 data, are used in the heat input rate calculations, use the regular missing data algorithm, rather than the inverse algorithm to provide substitute O_2 data for the heat input rate determinations.

For moisture missing data, use the regular missing data algorithm, unless Equation 19-3, 19-4, or 19-8 is used for NO_x emission rate determination, in which case, use the inverse missing data algorithm.

Use the missing data method of determination codes specified in Table 4a in Part 75.

References: § 75.33, § 75.66; 40 CFR Part 60, Appendix A, RM 19

Key Words: Missing data, Reporting

History: First published in March 2000, Update #12

Question 22.11

Topic: Representation of Subtractive Configuration in EDR

Question: How do I identify in the EDR submission the method of calculating NO_x or SO_2 mass emissions for the affected units?

Answer: Use RT 910 to identify the method used to calculate compliance. The following format (in italics) should be used to provide information on the determination of NO_x or SO_2 emissions for the affected and nonaffected units.

I. *This common stack EDR submission for the following units is a [SO_2 or NO_x] subtractive configuration.*

Main Common Stack: [Stack ID]
Affected unit IDs: [list IDs separated by commas]
Nonaffected unit IDs: [list IDs separated by commas]

Secondary Common Stack (if applicable)
for Nonaffected Units: [Stack ID]
Nonaffected unit IDs: [list IDs separated by commas]

Common Pipe (if applicable)
for Nonaffected Units: [Pipe ID]
Nonaffected unit IDs: [list IDs separated by commas]

II. *SO_2 mass emission methodology at the main common stack:*

Report one of the following, as applicable:

(1) Stack flow and SO_2 concentration CEM; or

(2) Other approved methodology at the common stack (describe)

III. SO_2 mass emission methodology for the nonaffected units or nonaffected units' secondary common stack:

Report one of the following, as applicable:

(1) SO_2 concentration CEM(s) and flow monitor(s); or

(2) Appendix D methodology

IV. NO_x mass emission methodology at the main common stack:

Report one of the following, as applicable:

(1) NO_x-diluent CEM and a stack flow monitor and diluent monitor; or

(2) NO_x concentration CEM and a stack flow monitor; or

(3) NO_x-diluent CEM and Appendix D heat input rate methodology

V. NO_x mass emissions methodology for the nonaffected units or nonaffected units' secondary common stack:

Report one of the following, as applicable:

(1) NO_x-diluent CEM(s), stack flow monitor(s) and diluent monitor(s); or

(2) NO_x concentration CEM(s) and stack flow monitor(s); or

(3) NO_x-diluent CEM(s) and apportionment of main common stack heat input rate; or

(4) NO_x-diluent CEM(s) and Appendix D heat input rate methodology

References: EDR v2.1, RT 910

Key Words: Electronic report formats

History: First published in March 2000, Update #12

Question 22.12

Topic: Subtractive Configuration Examples

Question: Are there any examples of units which currently have subtractive configurations?

Answer: Several examples will be provided in the future to describe actual subtractive stack situations to help explain reporting for these situations.

References: N/A

Key Words: N/A

History: First published in March 2000, Update #12

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SECTION 23
BYPASS STACKS

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Question 23.1 **REVISED**

Topic: Bypass Stacks

Question: What are the certification procedures and RATA requirements for an SO_2 CEM system used for monitoring scrubber bypass conditions?

Answer: In accordance with the provisions of § 75.16(c), § 75.17(c), and § 75.18(b), bypass stacks are subject to the same monitor installation and initial certification deadlines as monitors on primary stacks. The rule, however, includes two provisions that reduce the amount of testing that must be performed on bypass stacks. According to Section 6.5.2(b) of Appendix A to Part 75, flow rate RATAs for bypass stacks have to be performed at only one load level instead of two or three. In addition, Section 2.3 and Figure 1 of Appendix B to Part 75 allow RATA deadline extensions for monitors installed on bypass stacks. According to this section of the rule, only the quarters during which a bypass stack operates enough to meet the definition of a QA operating quarter are considered when determining RATA deadlines. For bypass stacks, the requirement that a RATA be completed semiannually or annually means that a RATA must be completed every two or four QA operating quarters, respectively (with an upper limit of eight calendar quarters between successive RATAs).

References: § 75.16(c); Appendix A, Section 6.5.2(b); Appendix B, Section 2.3

Key Words: Bypass stacks, Control devices, SO_2 monitoring

History: First published in Original March 1993 Policy Manual as Question 2.1; revised May 1993, Update #1; revised and renumbered in October 1999 Revised Manual

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SECTION 24
NO_x APPORTIONMENT

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BACKGROUND

I. Forty CFR 75.17(a)(1) and 75.17(a)(2)(i) allow the owner or operator of a group of NO_x affected units (see definition below) that exhaust into a common stack to demonstrate compliance with the applicable NO_x emission limits in the following ways:

A. Monitor the NO_x emission rate separately for each unit, in the duct from the unit to the common stack; or

B. Monitor the NO_x emission rate at the common stack <u>and</u> submit a compliance plan for approval by the permitting authority which indicates that:

(1) Each unit will comply with the most stringent NO_x emission limitation of any unit using the common stack; or

(2) Each unit will comply with the applicable NO_x emission limit by averaging its emissions with other units utilizing the common stack, pursuant to 40 CFR Part 76; or

(3) A petition will be submitted to determine each unit's NO_x compliance by an alternative method, satisfactory to the Administrator, using apportionment of the common stack NO_x emission rate and ensuring complete and accurate estimation of emissions.

II. Section 75.17(a)(2)(iii) allows an owner or operator of one or more NO_x affected units that exhaust into a common stack with NO_x nonaffected units (see definition below) to demonstrate that the NO_x affected unit(s) meet the applicable NO_x emission limitation(s) in the following ways:

A. Monitor the NO_x emission rate in the duct from each unit to the common stack; or

B. Petition the Administrator for approval of an alternative method to determine each unit's NO_x emission rate by an alternative method using apportionment of the common stack NO_x emission rate and ensuring complete and accurate estimation of emissions.

III. Section 75.17(b) allows an owner or operator of one or more Acid Rain units (see definition below) that exhaust into a common stack with one or more non-Acid Rain units (see definition below) to determine the NO_x emission rate(s) of the Acid Rain unit(s) in the following ways:

A. Monitor NO_x emission rate in the duct from each Acid Rain unit to the common stack; or

B. Petition the Administrator for approval of an alternative method to determine each unit's NO_x emission rate by an alternative method using apportionment of the common stack NO_x emission rate and ensuring complete and accurate estimation of emissions.

DEFINITIONS

Acid Rain Unit: A unit subject to any Acid Rain emissions limitation under 40 CFR Parts 72 and 74, or 76.

Main Common Stack: A stack through which the combined emissions from a group of units discharge to the atmosphere.

Non-Acid Rain Unit: A unit not subject to any SO_2 or NO_x Acid Rain emission limitation under 40 CFR Parts 72, 74, or 76.

NO_x Affected Unit: An Acid Rain unit which is subject to a NO_x emission limitation under 40 CFR Part 76.

NO_x Nonaffected Unit: An Acid Rain unit which is not subject to a NO_x emission limitation under 40 CFR Part 76.

Secondary Common Stack: A location in the ductwork, upstream of the main common stack, where the combined heat input rate and/or combined emissions from two or more units are monitored.

Question 24.1

Topic: Purpose of Common Stack NO_x Apportionment Policy

Question: What is the purpose of this policy?

Answer: If you have a common stack exhaust configuration consisting of either: (1) a group of NO_x affected units; or (2) a combination of NO_x affected units and NO_x nonaffected units; or (3) a combination of Acid Rain units and non-Acid Rain units, and if you wish to use common stack NO_x apportionment to determine unit-specific NO_x emission rates (see options I.B (3), II.B, and III.B under BACKGROUND section, above), this policy provides guidance on emissions monitoring and reporting.

Common stack NO_x apportionment is a methodology by which unit-specific NO_x emission rates are determined for a group of units that exhaust into a common stack, without monitoring each unit in the group separately.

You must petition the Administrator under § 75.66 for permission to use common stack NO_x apportionment. If your petition is consistent with the provisions of this policy, you have reasonable assurance that the petition will be approved and your monitoring will be consistent with other facilities using common stack NO_x apportionment.

References: § 75.17(a), § 75.17(b), § 75.66

Key Words: NO_x apportionment

History: First published in March 2000, Update #12

Question 24.2

Topic: NO_x Apportionment Methodologies

Question: For an exhaust configuration in which NO_x affected units and NO_x nonaffected units share a common stack, are there any common stack NO_x apportionment methodologies that may be approved by petition?

Answer: EPA considers two common stack NO_x apportionment methodologies to be approvable for the configuration: (1) the subtractive apportionment methodology; and (2) the simple NO_x apportionment methodology.

A. Subtractive Apportionment Methodology

(1) Summary of Method and Basis for Approval

Under the subtractive apportionment methodology, the hourly NO_x emission rate, heat input rate, and operating time are monitored at both at the common stack and at the NO_x nonaffected unit(s). These values are used to determine the total heat input and NO_x mass emissions at these locations. The hourly NO_x mass emissions and total heat input for the NO_x affected units are then determined by subtracting the measured NO_x mass emissions and total heat input values for the NO_x nonaffected units from the corresponding values measured at the common stack. Finally, the hourly NO_x emission rate for the NO_x affected units is calculated by dividing the NO_x mass emissions for the NO_x affected units by the total heat input for the NO_x affected units.

This methodology is approvable because it is based on a mass balance approach and uses Part 75 monitoring methodologies for both heat input and NO_x emission rate.

(2) Main Common Stack Monitoring Requirements

(a) Monitor the hourly NO_x emission rate at the main common stack using NO_x-diluent CEMS.

(b) Determine the hourly heat input rate at the common stack using a diluent monitor and a flow monitor.

(3) <u>NO_x Nonaffected Unit NO_x Emission Rate and Heat Input Rate Monitoring Requirements</u>

There are two options for monitoring NO_x emission rate at the NO_x nonaffected units:

(a) <u>Option 1</u>: You may install a NO_x-diluent CEMS in duct leading from each NO_x nonaffected unit to the main common stack. When this option is selected, determine the heat input rate for each NO_x nonaffected unit using one of the following methods:

(i) Install a flow monitor and a diluent monitor in the duct leading from each NO_x nonaffected unit to the main common stack; or

(ii) Use <u>individual</u> fuel flowmeters and the procedures of Appendix D of 40 CFR Part 75 (oil or gas-fired units only) to determine the heat input rate at each NO_x nonaffected unit. Heat input rate apportionment from a common pipe is not allowed in this case; or

(iii) Use Equation F-21a or F-21b in Appendix F of 40 CFR Part 75 (see Table 24-1) to apportion the heat input rate measured at the main common stack to <u>all</u> units in the configuration (<u>i.e.</u>, both NO_x affected and NO_x nonaffected units). Note that this method may only be used if the following three conditions are met:

(A) All units exhausting to the main common stack combust the same type of fuel and use the same F-factor; and

(B) All units exhausting to the main common stack have similar combustion efficiencies (± 10%); and

(C) There is no suitable location for a flow monitor and diluent monitor in the existing ductwork where NO_x emission rate is monitored.

If none of these three methods can be used to determine heat input rate, contact EPA for guidance.

(b) <u>Option 2</u>: If the emissions from a group of NO_x nonaffected units are combined prior to exhausting to the main common stack, you may monitor the combined NO_x emission rate for the group of units using a single NO_x-diluent CEMS. When this option is selected, designate the monitored location as a "secondary common stack" (see Definitions, above) and determine the heat input rate at the secondary common stack <u>and</u> at each NO_x nonaffected unit using one of the following methods:

(i) Monitor the heat input rate at the secondary common stack directly, using a flow monitor and diluent monitor. If this option is selected, use Equation F-21a or F-21b to apportion the heat input rate measured at the secondary common stack to the individual units. Replace the term t_{CS} in Equation F-21a or F-21b with the term t_{CS*}, where t_{CS*} is the stack operating time at the secondary common stack. Also, in the summation term in the denominator of Equation F-21a or F-21b, include only the hourly unit loads for the units associated with the secondary common stack.

Note that the restrictions listed under Paragraph (A)(3)(a)(iii) of this Question on the use of Equations F-21a and F-21b do not apply in this case; or

(ii) Monitor the heat input rate at each NO_x nonaffected unit using a fuel flowmeter and the procedures of Appendix D (oil and gas-fired units only), and determine the heat input rate at the secondary common stack using Equation F-25 (see Table 24-1, below); or

(iii) Monitor the heat input rate at a common pipe which serves only the units associated with the secondary common stack, using a fuel flowmeter and the procedures of Appendix D (oil and gas-fired units, only). In this case, you must first determine the individual unit heat input rates using Equation F-21a or F-21b and then use these rates, in conjunction with Equation F-25, to derive the heat input rate at the secondary common stack. In using Equations F-21a and F-21b, replace the term "t_{CS}" with the term "t_f", which is the fuel usage time for the common pipe.

Note that the restrictions listed under Paragraph (A)(3)(a)(iii) on the use of Equations F-21a and F-21b do not apply in this case; or

(iv) Use Equation F-21a or F-21b to apportion the heat input rate measured at the main common stack to <u>all</u> units in the configuration (<u>i.e.</u>, both NO_x affected and NO_x nonaffected units). Then use the apportioned unit level heat inputs and Equation F-25 to determine the heat input rate at the secondary common stack. Note that this option may only be used if the following three conditions are met:

(A) All units exhausting to the main common stack combust the same type of fuel and use the same F-factor; and

(B) All units exhausting to the main common stack have similar combustion efficiencies (±10%); and

(C) There is no suitable location for a flow monitor in the existing ductwork.

If none of these three methods can be used to determine the heat input rate for the NO_x nonaffected units, contact EPA for guidance.

(4) Hourly Heat Input Rate and Operating Time Reporting

Report hourly heat input rate and operating time in RT 300 for the main common stack, any secondary common stack(s), any common pipe(s) and for each unit in the configuration (i.e., for both NO_x affected and NO_x nonaffected units). Determine the hourly heat input rates for the main common stack, secondary common stack(s), common pipe(s) and for the individual NO_x nonaffected units as described in paragraphs (A)(2) and (A)(3) of this Policy Question. See Policy Question 24.3 for a discussion of how to determine the hourly heat input rates for the NO_x affected units.

Table 24-1: Hourly Heat Input Rate Apportionment and Summation Formulas

Equation Code	Formula	Where
F-21a	$HI_i = HI_{CS}\left(\frac{t_{CS}}{t_i}\right)\left[\frac{MW_i\ t_i}{\sum_{i=1}^{n} MW_i\ t_i}\right]$	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 for a particular unit (MWe) t_i = Operating time at a particular unit (hour or fraction of an hour) t_{CS} = Operating time at common stack (hour or fraction of an hour) n = Total number of units using the common stack or pipe i = Designation of a particular unit
F-21b	$HI_i = HI_{CS}\left(\frac{t_{CS}}{t_i}\right)\left[\frac{SF_i\ t_i}{\sum_{i=1}^{n} SF_i\ t_i}\right]$	HI_i = Heat input rate for a unit (mmBtu/hr) HI_{CS} = Heat input rate at the common stack or pipe (mmBtu/hr) SF_i = Gross steam load for a particular unit (klb/hr) t_i = Operating time at a particular unit (hour or fraction of an hour) t_{CS} = Operating time at common stack (hour or fraction of an hour) n = Total number of units using the common stack or pipe i = Designation of a particular unit
F-25	$HI_{cs} = \frac{\sum_{all-units} HI_u t_u}{t_{cs}}$	HI_{CS} = Heat input rate at the common stack (mmBtu/hr) HI_u = Heat input rate for a unit (mmBtu/hr) t_u = Operating time at a particular unit (hour or fraction of an hour) t_{CS} = Operating time at common stack (hour or fraction of an hour)

(5) Determination of NO_x Affected Unit(s) NO_x Emission Rate

Calculate the hourly, quarterly, and year-to-date NO_x emission rates for the NO_x affected units as follows:

(a) Determine a single hourly NO_x emission rate which applies to all NO_x affected units using Equation NS-1 (see Table 24-2). The terms NOx_{nonaff}, HI_{nonaff}, and t_{nonaff} in Equation NS-1, must be used consistently. For example, when NO_x emission rate and heat input rate are monitored at the unit level, NOx_{nonaff}, HI_{nonaff}, and t_{nonaff} are, respectively, the NO_x emission rate, heat input rate, and operating time for an individual NO_x nonaffected unit. When a group of NO_x nonaffected units is monitored at a secondary common stack, NOx_{nonaff}, HI_{nonaff}, and t_{nonaff} are, respectively, the NO_x emission rate, heat input rate, and operating time at the secondary common stack.

(b) Record, but do not report, the hourly NO_x emission rates determined from Equation NS-1 for the NO_x affected units. Maintain these data in a format suitable for inspection. It is sufficient to record these values in your DAHS if they can be retrieved upon request during an audit.

(c) Calculate the quarterly and year-to-date NO_x emission rate for each NO_x affected unit using Equation F-9 in Appendix F of 40 CFR Part 75. Report these values as described in Policy Question 24.9.

Table 24-2: Hourly NO_x Apportionment Formula for NO_x Affected Units Using the Subtractive Methodology

Equation Code	Formula	Where
NS-1	$NOx_{aff} = \dfrac{(NOx_{CS} \times HI_{CS} \times t_{CS}) - \sum_{all-nonafected}\left(NOx_{nonaff} \times HI_{nonaff} \times t_{nonaff}\right)}{\sum_{allaffected}(HI_{aff} \times t_{aff})}$	NOx_{aff} = Hourly NO_x emission rate for the NO_x affected units (lb/mmBtu) NOx_{CS} = Hourly NO_x emission rate at the common stack for the quarter (lb/mmBtu) HI_{cs} = Hourly heat input rate at the common stack (mmBtu/hr) t_{CS} = Common stack operating time (hr) NOx_{nonaff} = Hourly NO_x emission rate at the NO_x nonaffected unit or second common stack. (lb/mmBtu) HI_{nonaff} = Hourly heat input for the NO_x nonaffected unit (mmBtu) t_{nonaff} = NO_x nonaffected unit or second common stack

B. Simple NO_x Apportionment

(1) Summary of Method and Basis for Approval

Under simple NO_x apportionment, the hourly NO_x emission rate and heat input rate are monitored at the common stack and the hourly heat input rates for the individual units in the configuration are determined by direct measurement or by apportionment. The hourly emission rate of the NO_x affected unit(s) is calculated by dividing the total NO_x mass emissions from all units (in lb) by the total heat input (in mmBtu) from only the NO_x affected units.

This methodology is environmentally beneficial because it assures compliance of the NO_x affected units, by overestimating the NO_x emission rates for these units. The method assumes that all of the NO_x mass emissions measured in the common stack come from the NO_x affected units (i.e., that the NO_x nonaffected units contribute zero NO_x emissions to the total NO_x emissions measured at the common stack). The methodology may also provide environmental benefits by encouraging owners and operators of NO_x affected units to lower NO_x emissions at the NO_x affected units.

Despite these environmentally beneficial aspects, approval of this methodology must still be on a case-by-case basis. Section 75.17(a)(iii)(B) requires "complete and accurate" estimation of the regulated emissions (i.e., for the emissions from the NO_x affected units). EPA must therefore make a case-by-case determination of whether the assumption that all emissions come from the NO_x affected units will cause significant error that may preclude the use of this option.

EPA anticipates that simple NO_x apportionment will likely be used for common stack configurations involving low capacity, small, or low emitting NO_x nonaffected units.

(2) Main Common Stack Monitoring Requirements

(a) Monitor the hourly NO_x emission rate at the main common stack using a NO_x-diluent CEMS.

(b) Determine the hourly heat input rate at the main common stack using a flow monitor and a diluent monitor.

(3) Heat Input Rate Determination for the Individual Units

Determine the hourly heat input rate for each unit which exhausts to the main common stack (i.e., both NO_x affected and NO_x nonaffected units), using any of the following methods:

(a) Install a flow monitor and a diluent monitor in the duct leading from the unit to the main common stack; or

(b) Use a fuel flowmeter and the procedures of Appendix D (oil or gas-fired units only), to determine the heat input rate at the unit; or

(c) Monitor the heat input rate for a group of NO_x nonaffected units at a secondary common stack (see Definitions section, above) using a flow monitor and diluent monitor, and then apportion the heat input rate measured at the secondary common stack to the individual units, using Equation F-21a or F-21b. Replace the term t_{CS} in Equation F-21a or F-21b with the term t_{CS*}, where t_{CS*} is the stack operating time at the secondary common stack. Also, in the summation term in the denominator of Equation F-21a or F-21b, include only the hourly unit loads for the units associated with the secondary common stack.

Note that the restriction under Paragraph (B)(3)(e) of this Policy Question on the use of Equations F-21a and F-21b does not apply in this case; or

(d) Monitor the heat input rate at a common pipe which serves a group of NO_x nonaffected gas or oil fired units using the procedures of Appendix D. In this case, determine the individual unit heat input rates using Equation F-21a or F-21b.

Note that the restriction under Paragraph (B)(3)(e), below, on the use of Equations F-21a and F-21b does not apply in this case; or

(e) Use Equation F-21a or F-21b to apportion the heat input rate measured at the main common stack to all units (i.e., both NO_x affected and NO_x nonaffected units.

Note that this method may only be used if the following condition is met: all units exhausting to the main common stack combust the same type of fuel and use the same F-factor.

(4) Hourly Heat Input Rate and Operating Time Reporting for all Units

Report hourly heat input rate and operating time in RT 300 for the main common stack, any secondary common stack(s), any common pipe(s) and for each unit in the configuration (i.e.,both NO_x affected and NO_x nonaffected units). Determine the hourly heat input rates for the main common stack, secondary common stack(s), common pipe(s) and for the individual units as described in Paragraphs (B)(2) and (B)(3) of this Policy Question.

(5) Determination of NO_x affected Unit(s) NO_x Emission Rate

Calculate the hourly, quarterly and year-to-date NO_x emission rates for the NO_x affected unit(s) as follows:

(a) Determine the hourly NO_x emission rate for the NO_x affected units using Equation NS-2 (see Table 24-3). Equation NS-2 calculates a single NO_x emission rate which applies to all NO_x affected units.

(b) Record, but do not report, the hourly NO_x emission rates determined from Equation NS-2. Maintain these data in a format suitable for inspection. It is sufficient to record these values in your DAHS if they can be retrieved upon request during an audit.

(c) Calculate the quarterly and year-to-date NO_x emission rate for each NO_x affected unit using Equation F-9 in Appendix F of 40 CFR Part 75. Report these values as described in Policy Question 24.9.

Table 24-3: Hourly NO_x Apportionment Formula for NO_x Affected Units Using Simple NO_x Apportionment

Equation Code	Formula	Where
NS-2	$NO_{x_{aff}} = \dfrac{NO_{x_{cs}} \times HI_{cs} \times t_{cs}}{\sum\limits_{all-affected} HI_{aff} \times t_{aff}}$	NOx_{aff} = Hourly NO_x emission rate for the NO_x affected unit(s) (lb/mmBtu) NOx_{CS} = Hourly NO_x emission rate at the common stack (lb/mmBtu) HI_{CS} = Hourly heat input rate at the common stack (mmBtu/hr) t_{CS} = Common stack operating time (hr) HI_{aff} = Hourly heat input rate for the NO_x affected unit(s) (mmBtu/hr) t_{aff} = NO_x affected unit operating time (hr)

References: § 75.17

Key Words: NO_x apportionment

History: First published in March 2000, Update #12

Question 24.3

Topic: Reporting of Hourly Heat Input Rate

Question: How do I determine hourly heat input rate for the NO_x affected and NO_x nonaffected units in the configuration described in Question 24.2?

Answer: **A. Heat Input Rate Measured at the Main Common Stack Only**

For a qualifying configuration under Section A (subtractive apportionment) or Section B (simple apportionment) of Policy Question 24.2, in which heat input rate is measured only at the main common stack, apportion the hourly heat input rate at the common stack to each of the units in the configuration (both NO_x affected and NO_x nonaffected units) using Equation F-21a or F-21b in Appendix F of 40 CFR Part 75, for each stack operating hour (i.e., each hour in which fuel is combusted by any unit in the configuration). The summation term in the denominator of these equations must include all unit loads (for both the NO_x affected and NO_x nonaffected units).

B. Heat Input Rate Measured at the Main Common Stack and the NO_x Nonaffected Unit(s)

Use the procedures of this section to determine the heat input rate at the NO_x affected units only when heat input rate is monitored or measured at both the main common stack and at the individual NO_x nonaffected units (or at a secondary common stack serving only the NO_x nonaffected units).

(1) For all hours in which any NO_x affected unit is operating, use Equation SS-3a (see Table 24-2) to calculate the total heat input to the NO_x affected unit(s).

The term on the left side of the minus sign in Equation SS-3a is the hourly total heat input (mmBtu) at the main common stack and is the product of the measured heat input rate in RT 300/36 and the stack operating time in RT 300/18.

The term on the right side of the minus sign is the total hourly heat input for the NO_x nonaffected units and is the sum of the products of the measured RT 300/36 heat input rates (as determined under Question 24.2) and the RT 300/18 unit operating times for all of the NO_x nonaffected units.

When a group of NO_x nonaffected units is monitored at a single location, then, for those units, replace the term HI_{nonaff} t_{nonaff} in Equation SS-3a with the term HI_{CS*} t_{CS*}, where HI_{CS*} is the hourly heat input rate measured at the NO_x nonaffected units' monitoring location (designated as a secondary common stack) and t_{CS*} is the stack operating time at the secondary common stack.

Use the guidelines in the following three scenarios to ensure proper application of Equation SS-3a:

Scenario #1. For any hour in which the total heat input in mmBtu measured at the main common stack is greater than the total heat input of the NO_x nonaffected unit(s), use Equation SS-3a to obtain the total hourly heat input for the NO_x affected units.

For each hour in which Scenario # 1 applies, calculate the individual NO_x affected unit heat rates using Equation SS-3b (see Table 24-2). Note that the summation term in the denominator of Equation SS-3b includes only the hourly loads for the NO_x affected unit(s).

Scenario #2. For any hour in which the total heat input at the main common stack is less than or equal to the total heat input for the NO_x nonaffected unit(s), causing Equation SS-3a to give a negative or zero total heat input value for the NO_x affected units, follow these procedures:

(a) Invalidate the result obtained from Equation SS-3a;

(b) Consider the heat input rate measured at the main common stack to be correct;

(c) Disregard all heat input rate(s) measured at the NO_x nonaffected unit(s); and

(d) Apportion the heat input rate measured at the main common stack to all units (NO_x affected and NO_x nonaffected) in the subtractive stack configuration, using Equation F-21a or F-21b.

Scenario # 3. For any hour in which only NO_x affected units are operating, set the summation term in Equation SS-3a equal to zero, so that the total heat input for the NO_x affected units equals the heat input measured at the main common stack. Then, use Equation SS-3b to determine the hourly heat input rate for each NO_x affected unit.

(2) For any hour in which only NO_x nonaffected units are exhausting to the common stack, do not use Equation SS-3a. Assign a value of zero to the heat input rates for the NO_x affected units. Then, for the NO_x nonaffected units:

(a) Disregard all measured heat input rate values for the NO_x nonaffected units; and

(b) Assume that the heat input rate at the main common stack is correct and apportion this heat input rate to the NO_x nonaffected units using Equation F-21a or F-21b.

Table 24-4: Hourly Heat Input Formulas for NO_x Affected Units

Equation Code	Formula	Where
SS-3a	$HItot_{aff-hr} = HI_{CS}t_{CS} - \sum_{all-nonaff} HI_{nonaff}\, t_{nonaff}$	$HItot_{aff\text{-}hr}$ = Total hourly heat input for the NO_x affected units (mmBtu) HI_{CS} = Hourly heat input rate at the common stack (mmBtu/hr) HI_{nonaff} = Hourly heat input rate for a particular NO_x nonaffected unit (mmBtu/hr) t_{CS} = Operating time for the common stack (hr) t_{nonaff} = Operating time for a particular NO_x nonaffected unit (hr)
SS-3b	$HI_{aff} = \frac{1}{t_i} \times HItot_{aff-hr} \times \left(\frac{L_i t_i}{\sum_{all-aff} L_i t_i} \right)$	HI_{aff} = Hourly heat input rate for a particular NO_x affected unit (mmBtu/hr) $HItot_{aff\text{-}hr}$ = Total hourly heat input for all NO_x affected units (mmBtu) t_i = Operating time for a particular NO_x affected unit (hr) L_i = Hourly unit load for a particular NO_x affected unit in the subtractive stack configuration (MW or klb of steam per hour)

References: § 75.16(e)

Key Words: Heat input

History: First published in March 2000, Update #12

Question 24.4

Topic: Common Stack NO_x Apportionment for Other Configurations

Question: Question 24.2 addresses only common stack NO_x apportionment for a configuration consisting of NO_x affected and NO_x nonaffected units. What are the similarities and differences in the common stack NO_x apportionment methodologies for other configurations? In particular, address the following cases: (1) a configuration in which Acid Rain units share a common stack with non-Acid Rain units; and (2) a configuration in which a group of NO_x affected units share a common stack.

Answer: For the first configuration (Acid Rain and non-Acid Rain units sharing a common stack), the procedures and mathematics are exactly analogous to the case described in Question 24.2. Simply replace the term "NO_x affected unit" with the term, "Acid Rain unit" and replace the term "NO_x nonaffected unit" with the term "non-Acid Rain unit."

However, the second configuration (NO_x affected units sharing a common stack) is not analogous to the case described in Question 24.2, as there are no NO_x nonaffected units. Options (1), (2), and (3) in BACKGROUND section (I)(B), above, apply. If Option (3) is chosen, the owner or operator must submit a petition for an alternate apportionment method, satisfactory to the Administrator, ensuring complete and accurate estimation of emissions and no underestimation of any unit's emissions.

References: § 75.17

Key Words: NO_x apportionment

History: First published in March 2000, Update #12

Question 24.5

Topic: Monitoring Plan Requirements

Question: What are the monitoring plan requirements for the common stack NO_x apportionment described in Question 24.2?

Answer: For all units, including the NO_x nonaffected unit(s), report all standard unit-level record types including unit data, program data, monitoring methodologies, controls, and fuels (RTs 504, 505, 506, 585, 586, and 587).

For the main common stack serving both NO_x affected and NO_x nonaffected units, define the relationship between the stack and units in RTs 503 and submit all the standard monitoring plan information to support continuous emission monitoring systems (CEMS) at the common stack (RTs 510, 520, 530, 531, 535, and 536, as applicable). Report a RT 503 for each of the units served by the common stack.

For each NO_x nonaffected unit monitoring location, report all the standard monitoring plan information to support the CEMS, other monitoring systems or apportionment formulas at that location (RTs 510, 520, 530, 531, 535, 536, and 540). For each NO_x affected unit, report the appropriate heat input apportionment formula in RT 520 (see Question 24.3).

If the combined emissions from a group of units are monitored at a "secondary common stack" (see Definitions, above), report one RT 503 for each unit in the group, defining the relationship between the unit and the secondary common stack.

If a group of oil or gas-fired NO_x nonaffected units receives fuel from a common pipe, report one RT 503 for each unit in the group that defines the relationship between the unit and the common pipe.

If you petition and receive approval to use a minimum NO_x rate for missing data purposes, include the approved minimum rate in RT 531, using the code "MNNX" as the parameter and "APP" (approved) as the source of data code (see Policy Question 24.11).

Also include a narrative description of the NO_x apportionment configuration and reporting approach in RTs 910 (see Policy Question 24.12).

References: EDR v2.1 Reporting Instructions

Key Words: Monitoring plans

History: First published in March 2000, Update #12

Question 24.6

Topic: QA Requirements

Question: When common stack NO_x apportionment is used, what are the quality assurance requirements for monitoring systems installed in the duct(s) leading from NO_x nonaffected unit(s) or non-Acid Rain unit(s) to the common stack?

Answer: The monitoring systems located at the NO_x nonaffected unit or non-Acid Rain unit must be fully certified in accordance with testing required under § 75.21 and Appendix B to 40 CFR Part 75. The bias test requirement in Section 7.6 of Appendix A to 40 CFR Part 75 also applies to NO_x and flow rate monitoring systems installed on NO_x nonaffected units.

References: EDR v2.1 Reporting Instructions

Key Words: BAF, Quality assurance

History: First published in March 2000, Update #12

Question 24.7

Topic: Unit/Stack EDRs

Question: Should all of the units, pipes and stacks involved in a common stack NO_x apportionment configuration be included together in the same quarterly report?

Answer: Yes. Based on prior EPA guidance, all stack or pipe-level and associated unit-level data should be contained in a single quarterly report.

References: EDR v2.1 Reporting Instructions

Key Words: Electronic report formats

History: First published in March 2000, Update #12

Question 24.8

Topic: Reporting of Hourly NO_x Emission Rate and Heat Input Rate Data

Question: How do I report hourly data for a common stack NO_x apportionment?

Answer: Report hourly NO_x emission rate and heat input rate data for a common stack NO_x apportionment at each location where NO_x emission rate and/or heat input rate is measured (i.e., at the main common stack, any secondary common stack(s), any common pipe(s) and each unit monitoring location), as you would for any other NO_x monitoring configuration. Report only the measured data. Do not report hourly apportioned NO_x emission rate values for the NO_x affected units in RTs 320.

If you have additional reporting questions, contact EPA.

References: EDR v2.1 Reporting Instructions

Key Words: Electronic report formats

History: First published in March 2000, Update #12

Question 24.9

Topic: Cumulative Emissions Reporting

Question: What quarterly and annual NO_x emission rate data, operating hours, and total heat input data should I report in RTs 301 for the common stack NO_x apportionment described in Policy Question 24.2?

Answer: First note that this question does not cover reporting of CO_2 or SO_2 mass emissions.

Report separate RTs 301 for the main common stack, any secondary common stack(s), any common pipe(s), and each unit in the common stack configuration.

Two examples are provided for reference:

(1) If there is a main common stack, one NO_x affected unit, and one NO_x nonaffected unit in the configuration, report three RTs 301 in each quarterly report: one for the common stack, one for the NO_x affected unit, and one for the NO_x nonaffected unit.

(2) If there is a main common stack through which four units exhaust to the atmosphere, two of which are NO_x nonaffected and two of which are NO_x affected, and if the NO_x nonaffected units are monitored at a secondary common stack location, report six record types 301, one at the main common stack, one at the secondary common stack, and one for each unit.

In the RT 301 for the main common stack, report the quarterly and year-to-date NO_x emission rates (lb/mmBtu), operating hours, and heat input (mmBtu) values derived from the common stack monitors. Calculate all quarterly and cumulative emissions and heat input values in accordance with the applicable sections of the EDR v2.1 Reporting Instructions.

In RT 301 for each NO_x nonaffected unit, report all required quarterly and cumulative heat input data (either measured or apportioned as appropriate) and operating hours. Also report the NO_x emission rate if it is individually monitored.

In the RT 301 for a secondary common stack location at which a group of NO_x nonaffected units is monitored (if applicable), report all quarterly and cumulative NO_x emission rate, operating hours, and heat input values derived either from the hourly CEMS measurements made at the monitoring location, or apportioned to that location.

In the RT 301 for a common pipe, report the quarterly and cumulative heat input values and operating hours derived from the hourly heat input rate measurements and fuel usage times at the common pipe.

In RT 301 for each NO_x affected unit, report the quarterly and cumulative heat input and operating hours that were derived using one of the accepted methodologies in this policy. Also report the NO_x emission rate, as apportioned to the unit.

References: EDR v2.1 Reporting Instructions

Key Words: Electronic report formats, NO_x apportionment

History: First published in March 2000, Update #12

Question 24.10

Topic: Missing Data Requirements

Question: What missing data requirements apply in the common stack NO_x apportionment stack configuration described in Question 24.2?

Answer: For the common stack, use the standard missing data procedures in § 75.33.

For monitors located at either the individual NO_x nonaffected units or at a secondary common stack serving only the NO_x nonaffected units use "inverse" missing data procedures for NO_x, CO_2, and flow rate missing data (i.e., substitute the 10th percentile value when the standard missing data procedures in § 75.33 require the 90th percentile value, use the 5th percentile value in lieu of the 95th percentile value, use the minimum value in the look back periods instead of the maximum value and use zeros for the minimum potential NO_x emission rate or minimum potential flow rate for any hours in which maximum potential values would ordinarily be used under Subpart D of Part 75). The owner or operator may petition the Administrator under § 75.66 to use minimum potential values other than zero.

If O_2 data, rather than CO_2 data is used in the heat input rate calculations, use the "regular" missing data algorithm, rather than the inverse algorithm, to provide substitute O_2 data for the heat input rate determinations.

For moisture missing data, use the regular missing data algorithm, unless Equation 19-3, 19-4, or 19-8 is used for NO_x emission rate determination, in which case, use the inverse missing data algorithm.

Use the missing data method of determination codes specified in Table 4a in Part 75.

References: § 75.33, § 75.66

Key Words: Missing data

History: First published in March 2000, Update #12

Question 24.11

Topic: Representation of NO_x Apportionment in EDR

Question: What record types do I use in my quarterly report submittal to identify the agreed upon method of calculating the overall NO_x emission rate for the NO_x affected units when I am using either of the common stack NO_x apportionment methodologies described in Question 24.2?

Answer: Use RT 910 (cover letter text record) to identify the method used to calculate the NO_x emission rate for compliance purposes. The following format (in italics) should be used to identify how the NO_x emission rate is determined for the NO_x affected and NO_x nonaffected units.

I. This common stack EDR submission for the following units uses an approved NO_x apportionment methodology.

Main Common Stack:	[Stack ID]
NO_x affected unit IDs:	[list IDs separated by commas]
NO_x nonaffected unit IDs:	[list IDs separated by commas]
Secondary Common Stack (if applicable):	[Stack ID]
NO_x nonaffected unit IDs:	[list IDs separated by commas]
Common Pipe (if applicable):	[Pipe ID]
NO_x nonaffected unit IDs:	[list IDs separated by commas]

II. Method used to determine NO_x emission rate at the NO_x affected units:

Report one of the following:

(1) Subtractive apportionment methodology using Equation NS-1; or

(2) Simple NO_x apportionment using Equation NS-2.

III. Heat input methodology for the NO_x nonaffected units:

Report at least one of the following:

(1) Duct level flow monitor and diluent monitor; or

(2) Appendix D fuel flowmeter; or

(3) Common stack heat input apportionment using Equation F-21a or F-21b.

References: EDR v2.1 Reporting Instructions

Key Words: Electronic report formats, NO_x apportionment

History: First published in March 2000, Update #12

Question 24.12

Topic: Approvable NO_x Apportionment Methodologies

Question: Are these the only approvable NO_x apportionment methodologies?

Answer: This policy guidance does not preclude other NO_x apportionment methodologies being considered or approved.

References: N/A

Key Words: NO_x apportionment

History: First published in March 2000, Update #12

Question 24.13

Topic: NO_x Apportionment Methodologies Examples

Question: Are there any examples of units which currently have NO_x apportionment situations?

Answer: Several examples will be provided in the future to describe actual NO_x apportionment situations to help explain reporting for these situations.

References: N/A

Key Words: NO_x apportionment

History: First published in March 2000, Update #12

SECTION 25
APPENDIX D

Page

Question 25.1 REVISED

Topic: GCV Sampling Frequency for Pipeline Natural Gas

Question: If I have a unit using a default emission rate to calculate SO_2 emissions from pipeline natural gas, how often does fuel sampling and analysis have to be performed to determine the GCV?

Answer: For gas, monthly fuel sampling and analysis is required for every month that gaseous fuel is combusted. The sampling and analysis may be done either by the owner or operator or by the fuel supplier. This requirement does not apply for any month in which pipeline natural gas is combusted for a period less than 48 hours, provided that at least one analysis for GCV is done each quarter that the unit operates. Oil sampling still must be done in accordance with the procedures in Section 2.2 of Appendix D.

References: Appendix D, Section 2.3.4.1; Appendix F, Section 5.5

Key Words: Excepted methods, Gas-fired units, SO_2 monitoring

History: First published in July 1995, Update #6 as Question 2.7; revised and renumbered in October 1999 Revised Manual

Question 25.2 REVISED

Topic: Measuring Gas Sulfur Content

Question: Is it permissible for a gas supplier to measure the amount of sulfur-containing compounds added to pipeline natural gas instead of sampling the sulfur content in the pipeline natural gas?

Answer: No. Appendix D requires sampling of the gaseous fuel by specified methods.

References: Appendix D, Section 2.3.3.1.2

Key Words: Excepted methods, Fuel sampling, SO_2 monitoring

History: First published in November 1995, Update #7 as Question 2.8; revised and renumbered in October 1999 Revised Manual

Question 25.3 REVISED

Topic: Diesel Fuel Sampling

Question: How are we to do as-delivered fuel sampling of diesel fuel, and which sulfur value is used to calculate SO_2 mass emissions? Can we just use the sulfur content from our most recent delivery, as provided by our vendor?

Answer: Appendix D, Section 2.2.4.3 states: "Oil sampling may be performed either by the owner or operator of an affected unit, an outside laboratory, or a fuel supplier, provided that samples are representative and that sampling is performed according to either the single tank composite sampling procedure or the all-levels sampling procedure in ASTM D4057-88. . ."

This may be accomplished by taking a sample from the:

(1) Shipment tank or container upon receipt.

(2) Supplier's storage container that holds the fuel (if fuel is added to the container, a new sample must be taken).

SO_2 mass emissions then should be calculated using either the highest value sampled during the previous calendar year or the maximum value indicated in the fuel supply contract unless the actual value obtained from the most recent sample is higher.

References: Appendix D, Section 2.2.4.3

Key Words: Excepted methods, Fuel sampling, Oil-fired units, SO_2 monitoring

History: First published in November 1995, Update #7 as Question 2.9; revised and renumbered in October 1999 Revised Manual

Question 25.4 REVISED

Topic: Fuel Usage Time

Question: Do invalid one-minute fuel flow data points get counted in the determination of the hourly fuel usage time? For example, if we have valid one-minute data from minute 1 through 28, invalid data from minute 29 through 35 and valid "0" data (fuel off) from minute 36 through 60, what is the fuel usage time?

Answer: You may report the actual portion of each clock hour in which the unit combusted fuel, to the nearest hundredth of an hour (0.58 in this example, based on minutes 1 through 35), or you may report the number of quarter hours in which the unit combusted fuel, rounded up to the next highest quarter hour (0.75 in this example). Note that while the hourly average fuel flow rate is based upon the valid data points collected while the fuel was being burned (i.e., the average of the data collected between minutes 1 and 28), the fuel usage time is based upon the time during which fuel was burned regardless of whether or not valid fuel flow rate data were obtained.

References: Appendix D; RT 302, RT 303

Key Words: Excepted methods, Fuel sampling, SO_2 monitoring

History: First published in November 1995, Update #7 as Question 2.10; revised and renumbered in October 1999 Revised Manual

Question 25.5

Topic: Appendix D Fuel Sampling -- Usage of Multiple Fuels

Question: Section 2.2.4 of Appendix D states that if multiple oil supplies with different sulfur contents are combusted in one day, the utility should sample the highest sulfur content fuel. How do we know which sulfur content is higher until it is sampled and analyzed?

Answer: If different types of fuel with different expected sulfur contents are combusted on one day (e.g., #2 fuel oil and #6 fuel oil), the utility may sample only the type of fuel with the expected higher sulfur content. If the same type of fuel from different suppliers are burned, the utility must sample both fuels to determine which has a higher sulfur content.

References: Appendix D, Section 2.2.4.1

Key Words: Excepted methods, Fuel sampling, Oil-fired units, SO_2 monitoring

History: First published in November 1995, Update #7 as Question 2.11; renumbered in October 1999 Revised Manual

Question 25.6 **REVISED**

Topic: Appendix D Fuel Sampling -- Time for Results

Question: Appendix D requires results of sampling within 30 days of sampling. Does this mean on site or entered into the DAHS for processing?

Answer: The results of sampling should be available on site at the plant within 30 days of sampling. Also, in the event of an audit, EPA may request that these values be made available to the Agency within five days of the request. As a standard operating procedure it is acceptable to enter the data at the end of the quarter. However, in the event of an onsite audit by EPA or State agency staff, the operator must be able to enter the data in the DAHS and generate the calculated values. Furthermore, the data must be retrievable from the DAHS the day of an onsite audit.

References: Appendix D, Sections 2.2.8, 2.3.3.1.4

Key Words: DAHS, Excepted methods, Fuel sampling, SO_2 monitoring

History: First published in November 1995, Update #7 as Question 2.12; renumbered in October 1999 Revised Manual

Question 25.7 REVISED

Topic: Backup Fuel

Question: What is *backup fuel*, as referred to in various sections of 40 CFR Part 75? Do Appendix D fuel flowmeters measuring backup fuel qualify for less frequent fuel flowmeter calibrations?

Answer: The term backup fuel is defined in § 72.2. For Part 75, backup fuel means "the fuel provides less than 10.0 percent of the heat input to a unit during the three calendar years prior to certification testing of the primary fuel and the fuel provides less than 15.0 percent of the heat input to a unit in each of those three calendar years." For example, for a gas-fired unit, oil may be a backup fuel.

Fuel flowmeters that measure the flow of backup fuel are calibrated at the same frequency as flowmeters that measure the flow of primary fuel (i.e., once every four fuel flowmeter QA operating quarters (as that term is defined in § 72.2)). (See Section 2.1.6(a) of Appendix D.)

References: § 72.2, Appendix D, Section 2.1.6(a)

Key Words: Backup fuel, Excepted methods, Flow monitoring, Fuel sampling, SO_2 monitoring

History: First published in March 1996, Update #8 as Question 3.11; revised and renumbered in October 1999 Revised Manual

Question 25.8

Topic: Use of Billing Fuel Flowmeter

Question: Can we use a billing fuel flowmeter for oil?

Answer: Yes, provided that the requirements of Section 2.1.4.2 of Appendix D are met.

References: Appendix D, Section 2.1.4.2

Key Words: Excepted methods

History: First published in October 1999 Revised Manual

Question 25.9

Topic: Vendor-supplied Sulfur Values

Question: Can we use vendor-supplied values for Appendix D fuel sampling requirements (e.g., percent sulfur)?

Answer: Yes.

References: Appendix D, Sections 2.2 and 2.3

Key Words: Excepted methods, Fuel sampling

History: First published in October 1999 Revised Manual

Question 25.10

Topic: Certified Fuel Flowmeter -- Emergency Fuel Exemption

Question: Our plant generally burns only natural gas but also has the capability to burn oil. Section 2.1.4.3 of Appendix D has a new option for emergency fuels which does not require the use of a certified fuel flowmeter. Can you elaborate on how this monitoring option is to be implemented?

Answer: First, the fuel must qualify as an emergency fuel as described in Appendix D Section 2.1.4.3. This means accepting a permit restriction which limits the use of the fuel to emergency situations in which the primary fuel is not available. EPA considers the following circumstances to be emergency situations: (1) if the supplier of the primary fuel cannot provide that fuel (e.g., gas curtailment); and

(2) if the primary fuel handling system is inoperable and is being repaired. Note that the permit restriction may also contain provisions which allow the unit to combust the emergency fuel for short test periods as a normal maintenance practice to verify that the unit can safely combust the emergency fuel.

If the necessary permit restriction is in place, then, according to Section 2.1.4.3 of Appendix D, the use of a certified fuel flowmeter is not required when the emergency fuel is combusted, and the maximum rated hourly heat input may be used for emissions reporting. Use the following EDR reporting guidelines when this option is selected:

Reporting Data in RT 302

! In RT 302, report data in fields 1, 4, 13, 19, and 56 in the normal fashion.

! Do not define or report an emergency fuel flowmeter monitoring system in field 10. Leave this field blank.

! Also leave fields 32, 59, 69, 74, 75, 83, 88, and 92 blank.

! Report the maximum mass flow rate of oil for the unit in column 21 and report a source of data code of "4" in field 31. Calculate the maximum oil mass flow rate using the following equation:

$$MFFR = \frac{MHHI}{GCV_{Emer}} \times 10^{6}$$

(Equation EF-1)
Where:

MFFR	=	Maximum mass flow rate of oil for the unit (lb/hr)
MHHI	=	Maximum rated hourly heat input rate for the unit as reported in RT 504 (mmBtu/hr).
GCV_{Emer}	=	Gross calorific value of the emergency fuel (Btu/lb). Use either a value measured by one of the accepted sampling methods in Appendix D or use the default fuel GCV values in Table D-6 of Appendix D (i.e., 19,500 Btu/lb for residual oil or 20,000 Btu/lb for diesel, kerosene or other distillate fuel oils of grades 1 or 2).
10^6	=	Conversion factor from mmBtu to Btu

! Report the GCV of the oil in field 34, in units of Btu/lb.

! In column 44, report "0" if a measured value of fuel GCV is used or "1" if a default value is used.

! In column 45, report the unit heat input rate (i.e., the MHHI, as defined in Equation EF-1, above).

! In column 52, report the total unit operating time for the hour. Note that the heat input rate in column 45, multiplied by the operating time in field 52 should equal the total hourly heat input reported for the unit in column 57 of RT 300.

! In field 89, *always* report "S" to indicate that a single fuel was combusted during an hour when the emergency fuel is combusted. Do not attempt to account for multiple fuel combustion during any hour(s) in which the emergency fuel is combusted.

! In column 90, report either the appropriate code for GCV sampling or code "8" if a default GCV value is used.

Reporting SO_2 Mass Emissions in RT 313

! In RT 313 report fields 1, 4, 13, 19, 30, and 37 (optional) in the normal way.

! Do not define or report an emergency fuel flowmeter monitoring system in field 10. Leave this field blank.

! In column 21, report the sulfur content of the oil. Report either a measured value obtained by one of the sulfur sampling options in Appendix D or a default sulfur content from Table D-6 of Appendix D.

! In column 44, report either the sampling option used for the oil sulfur content or code "8" for a default % sulfur value from Table D-6.

References: Appendix D, Section 2.1.4.3

Key Words: Electronic report formats, Excepted methods, SO_2 monitoring

History: First published in October 1999 Revised Manual

Question 25.11

Topic: Missing Data Substitution -- Use of Multiple Fuels

Question: There are Acid Rain-only sources that are reporting using EDR v1.3 but are having a problem reporting SO_2 mass emissions when burning two different oils or two different gases during the same hour and doing missing data substitution for fuel flow rate for the same hours. Can I use the EDR v2.1 Reporting Instructions when doing missing data substitution for RT 302 and RT 313 for oil and RT 303 and 314 for gas?

Answer: Yes, there are two situations where this is applicable. First, when burning two different oils for the same hour and doing missing data substitution you should report a valid monitoring system ID in at least one of the RT 302 if the oil flow rate data are missing for both oils. Report this same monitoring system ID in the companion RT 313. Second, when burning two different gases for the same hour and doing missing data substitution you should report a valid monitoring system ID in at least one of the RT 303 if the gas flow rate data are missing for both fuels. Report this same monitoring system ID in the companion RT 314.

References: Appendix D

Key Words: Excepted methods, Missing data, SO_2 monitoring, Reporting

History: First published in October 1999 Revised Manual

Question 25.12

Topic: Failure of Fuel Flow-to-load Test

Question: If we fail a quarterly fuel flow-to-load ratio test, what data are invalidated?

Answer: The data are invalidated starting with the first hour of the quarter <u>following</u> the quarter in which the test was failed.

References: Appendix D, Section 2.1.7.4(b)

Key Words: Data validity, Fuel flow-to-load test

History: First published in October 1999 Revised Manual

Question 25.13

Topic: Use of Quarterly Operating Data in Fuel Flow-to-load Test

Question: Under Appendix D, for a fuel flow-to-load test, why are we required to use more of the quarterly operating data than is required for the stack flow-to-load test?

Answer: The fuel flow-to-load ratio test requires the use of more of the quarterly data than the stack flow-to-load ratio test, because it is not tied to a baseline test like the stack flow-to-load test, which uses a RATA test at a specific load level as the baseline.

Note that EPA evaluated real fuel flow rate data and responded to comments on the 1998 proposed rule by extending the allowable data exclusion to the lower 25% of the range of operation instead of the lower 10%.

References: Appendix D, Section 2.1.7.1(a)

Key Words: Excepted methods, Fuel flow-to-load

History: First published in March 2000, Update #12

Question 25.14

Topic: Use of Quarterly Fuel Flow-to-load Test

Question: May I perform the quarterly fuel flow-to-load ratio test (as described in Section 2.1.7 of Appendix D) for one quarter and then change my mind and stop reporting the results of that test in subsequent quarters?

Answer: Yes, as long as you fulfill the QA requirements for the fuel flowmeter. If, at the beginning of the calendar quarter in which you decide to discontinue reporting the fuel flow-to-load ratio test results, a historical lookback shows that four or more "fuel flowmeter QA operating quarters" have passed since the last fuel flowmeter calibration, then you must recalibrate the fuel flowmeter prior to the end of the quarter in which the fuel flow-to-load ratio analysis is discontinued. If fewer than four "fuel flowmeter QA operating quarters" have passed since the last fuel flowmeter calibration you may wait until the "normal" deadline to perform the required recalibration.

Note, however, that if your decision to discontinue performing the quarterly fuel flow-to-load data analysis is based on the results of a failed fuel flow-to-load test, you may <u>not</u> ignore these test results. In this case you must report the results of the failed test and you must follow the procedures of Appendix D, Section 2.1.7.4, "Consequences of Failed Fuel Flow-to-Load Ratio Test." This applies even if the failed fuel flow-to-load test occurs prior to the completion of four fuel flowmeter QA operating quarters.

References: Appendix D, Sections 2.1.7.3, 2.1.7.4

Key Words: Excepted methods, Fuel flow-to-load test

History: First published in March 2000, Update # 12

Question 25.15

Topic: Alternative Calibration Method for Coriolis Meters

Question: Is a method for Coriolis meters going to be part of future technical corrections?

Answer: The Agency is not aware of any current voluntary consensus standards (ASTM, AGA, ANSI ISO, etc.) that provide an alternative method of calibration for Coriolis type fuel flowmeters. Therefore, the acceptable methods for calibrating Coriolis fuel flowmeters are the methods described in Appendix D, Section 2.1.5.2 (i.e., (1) calibration against a reference meter installed in line with the Coriolis meter; or (2) laboratory calibration by the manufacturer).

References: Appendix D, Section 2.1.5.2

Key Words: Excepted methods

History: First published in March 2000, Update # 12

Question 25.16 NEW

Topic: Fuel Flowmeter Accuracy Testing -- Use of Billing Meter

Question: May I use a billing meter as an in-line reference meter to test the accuracy of a Part 75 fuel flowmeter?

Answer: You may use any in-line meter (including a billing meter) as a reference meter to calibrate a Part 75 fuel flowmeter, if the billing meter meets the criteria in Section 2.1.5.2(a) of Appendix D and the quality assurance requirements in Sections 2.1.6.1 and 2.1.6.4 of Appendix D. That is:

(1) If the billing meter is an orifice, nozzle or venturi-type meter, you may use it as a reference meter if:

(a) It meets the design criteria of AGA Report No. 3 or ASME MFC-3M-1989;

(b) Calibrations of the temperature, pressure, and differential pressure transmitters (or transducers) are performed and passed according to Section 2.1.6.1 of Appendix D, immediately prior to the comparison between the billing meter and the Part 75 fuel flowmeter; and

(c) A visual inspection of the meter's primary element has been performed and passed within the previous three years (12 calendar quarters) prior to the comparison.

(2) A billing meter other than an orifice, nozzle, or venturi-type may be used as a reference meter, provided that the billing meter either:

(a) Has passed an accuracy test within the last 365 days, using one of the standards listed in Section 2.1.5.1 of Appendix D; or

(b) Qualifies for a waiver from accuracy testing, under Section 2.1.5.2(c) of Appendix D.

References: Appendix D, Sections 2.1.5.1, 2.1.5.2, 2.1.6.1, and 2.1.6.4

Key Words: Accuracy testing, Billing meter, Fuel flowmeter

History: First published in December 2000, Update #13

Question 25.17 NEW

Topic: Definition of a "Fuel Flowmeter QA Operating Quarter"

Question: Please clarify the term "fuel flowmeter QA operating quarter" as defined in 40 CFR § 72.2.

Answer: The term "fuel flowmeter QA operating quarter" is both fuel-specific and monitoring system-specific. For example, a unit that burns gas for 500 hours in a quarter and oil for 100 hours in a quarter has a gas "fuel flowmeter QA operating quarter" (because gas was burned for $\geq$ 168 hours), but does not have an oil "fuel flowmeter QA operating quarter."

In the example above, if the gas fuel flowmeter system had consisted of multiple fuel flowmeters the "fuel flowmeter QA operating quarter" would have been counted against each of the installed meters in the system (see Note, below), even if one or more of the individual meters (e.g., a return meter) may have operated for less than 168 hours in the quarter. Each time that a "fuel flowmeter QA operating quarter" is charged against a particular flowmeter, it counts toward the determination of the deadline for the next accuracy test of the flowmeter.

Note: If fuel flowmeter components are rotated (as described in the "Revised EDR Version 2.1 Reporting Instructions," in paragraph (d) of the instructions for RT 510), the fuel flowmeter system(s) listed in the monitoring plan will have multiple fuel flowmeter components. However, not all of the component flowmeters listed in a system will be installed at any given time (e.g., the other components may be in storage). Fuel flowmeter QA operating quarters are counted only against installed flowmeter components.

References: § 72.2

Key Words: Fuel flowmeter QA operating quarter

History: First published in December 2000, Update #13

Question 25.18 NEW

Topic: Fuel Flowmeter Calibration -- Rotation of Fuel Flowmeters

Question: For purposes of quality assurance, I rotate my Appendix D fuel flowmeters, as described in the "Revised EDR Version 2.1 Reporting Instructions," under RT 510, paragraph (d). Section 2.1.6 of Appendix D requires fuel flowmeters to be recalibrated, at a minimum, once every four "fuel flowmeter QA operating quarters." If I calibrate a fuel flowmeter and temporarily put it in storage, how long can the meter remain in storage without being recalibrated? When the meter is returned to service, how do I determine the deadline for the next flowmeter accuracy test?

Answer: Manufacturers of fuel flowmeters recommend that the flowmeters not be kept too long in storage without recalibrating them. Estimates of how long is "too long" vary from vendor to vendor. Use the following guidelines. You may keep a flowmeter in storage without recalibrating it for up to three years (12 calendar quarters) after the quarter in which it was last calibrated, unless more frequent recalibration is recommenced by the manufacturer.

When a calibrated flowmeter is brought back into service after being in storage, its next accuracy test will be due, as specified in section 2.1.6 of Appendix D, within four "fuel flowmeter QA operating quarters" (beginning with the quarter in which the meter is brought into service), not to exceed 20 calendar quarters from the quarter of the last accuracy test of the flowmeter (see also Policy Question 25.17).

References: Appendix D, Section 2.1.6; Revised EDR Version 2.1 Reporting Instructions

Key Words: Calibration, Fuel flowmeters, Rotate

History: First published in December 2000, Update #13

Question 25.19 NEW

Topic: Fuel Flow-to-load Ratio Test -- Baseline Data Collection

Question: If I have a fuel flowmeter system consisting of multiple components (e.g., a system having a main fuel flowmeter and a recirculating meter), and I elect to extend the deadline for the next fuel flowmeter quality assurance test by using the optional fuel flow-to-load ratio test in Section 2.1.7 of Appendix D, which fuel flowmeter quality assurance test date should be used as the reference point for the baseline data collection?

Answer: Begin collecting baseline data only after all component meters in the system have passed their required QA tests. This is consistent with the EDR reporting instructions for the fuel flow-to-load ratio test (RTs 629 and 630), which specify that the test is performed on a system basis. To ensure that the baseline data are collected in a timely manner, EPA recommends that all of the flowmeters in the system be calibrated within a 30 calendar day period. The baseline data collection period should start with the first operating hour after the last meter in the system has been QA tested and (if applicable) re-installed.

References: Appendix D, Sections 2.1.6 and 2.1.7

Key Words: Baseline data, Fuel flowmeter certification, Fuel flow-to-load ratio test

History: First published in December 2000, Update #13

Question 25.20 NEW

Topic: Fuel Flow-to-load Ratio Test -- Baseline Data Collection

Question: When the optional fuel flow-to-load ratio test in Section 2.1.7 of Appendix D is used to extend fuel flowmeter accuracy test deadlines, "baseline" data must be collected after each fuel flowmeter accuracy test, to establish a reference fuel flow-to-load ratio or gross heat rate (GHR). Part 75 requires a minimum of 168 hours of baseline data and allows up to four calendar quarters to collect it. For many affected units, 168 hours of baseline data can be collected within one quarter. Why does EPA allow four quarters to collect baseline data for the reference fuel flow-to-load ratio or GHR?

Answer: Four calendar quarters are allowed to collect the baseline data principally for units that operate infrequently and/or units that have frequent startups and shutdowns. For such units, it can take two or more quarters to obtain 168 hours of baseline data, particularly if the allowable data exclusions in Section 2.1.7.1(a) of Appendix D are claimed (e.g., for "ramping" hours). However, note that even for units that operate frequently and seldom start up or shut down, it may be appropriate to collect the fuel flow-to-load ratio or GHR baseline data over multiple calendar quarters. The owner or operator should use good engineering judgment in determining the amount of baseline data necessary to determine the reference value of the fuel flow-to-load ratio or GHR. The baseline data should capture any seasonal and operational variations, to ensure that the reference ratio or GHR represents the average operation of the unit.

References: Appendix D, Section 2.1.7

Key Words: Baseline data, Fuel flow-to-load ratio test, GHR

History: First published in December 2000, Update #13

Question 25.21 NEW

Topic: Default Minimum Fuel Flow Rate

Question: When an Appendix D fuel flowmeter is used to measure unit heat input, occasionally, during unit start-up, the gas fuel flow rate is below the detection limit of the fuel flowmeter. If this occurs near the end of a clock hour, it can result in zero fuel flow rate and zero heat input being recorded for the hour, which will trigger error messages in ETS. May I define and report a minimum default fuel flow rate for any on-line period in which the fuel flow rate is below the flowmeter's detection limit?

Answer: Yes. You may define a minimum default fuel flow rate for periods when fuel is being combusted but the flow rate is below the detection limit of the fuel flowmeter. Define this value in the hardcopy portion of your monitoring plan. The default value should correspond either to the minimum flow rate the meter is capable of measuring or the lowest fuel flow rate which ensures that non-zero heat input information will be reported in RT 300 and in RTs 302 and 303 (as applicable).

References: Appendix D, Section 2.1, Revised EDR Version 2.1 Reporting Instructions

Key Words: Default, Fuel flow rate, Minimum value

History: First published in December 2000, Update #13

Question 25.22 NEW

Topic: Appendix D -- Sampling Methodologies

Question: Once I have selected an Appendix D sampling methodology to determine fuel sulfur content, GCV, or density, under what circumstances may I change methodologies?

Answer: Once you have selected a sampling methodology you must continue to use that methodology and the missing data routines associated with it, unless you choose to make a permanent change in your approach. You may not switch methodologies to avoid reporting substitute data.

References: Appendix D, Sections 2.3 and 2.4

Key Words: Density, Fuel sulfur content, GCV, Missing data

History: First published in December 2000, Update #13

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SECTION 26
APPENDIX E

Question 26.1 REVISED

Topic: Appendix E -- Testing

Question: In the procedures in Appendix E to Part 75, how many sample runs of Method 7E need to be run at each load level? How long does each run last?

Answer: Conduct three sample runs at each load level as stated in Section 2.1.2.3 of Appendix E.

When the sampling points specified in Section 2.1.2.1 of Appendix E are used, the first sampling point of each traverse should be sampled for at least one minute plus twice the average measurement system response time. All other sampling points in each traverse should be performed for at least one minute plus the average measurement response time. However, if permission is obtained through a petition under § 75.66 to use fewer sampling points than are specified in section 2.1.2.1 of Appendix E, ensure that the total sampling time for each test run is $\geq$ 15 minutes, and divide the total sampling time for the run evenly among all sample points.

References: Appendix E, Section 2.1.2.3

Key Words: Excepted methods, NO_x monitoring

History: First published in May 1993, Update #1 as Question 4.3; revised July 1995, Update #6; revised and renumbered in October 1999 Revised Manual

Question 26.2

Topic: Excepted Methods -- Applicability

Question: Can a gas-fired unit performing testing to meet the requirements of Appendix E be exempt from including this period of testing in the calculation of unit operating hours for the purpose of determining eligibility as a peaking unit (or as a gas-fired unit)?

Answer: No. All unit operating hours, including those hours during the performance tests required to establish NO_x-load correlations used for the Appendix E procedure must be included in the determination of continued eligibility as a peaking unit (or as a gas-fired unit).

References: § 75.12(d); Appendix E

Key Words: Excepted Methods, NO_x monitoring

History: First published in May 1993, Update #1 as Question 4.7; renumbered in October 1999 Revised Manual

Question 26.3 REVISED

Topic: Excepted Methods - Traverse Points

Question: For NO_x stack testing for Appendix E to Part 75, how should I select sampling locations for each point in a traverse for each run?

Answer: For a stationary gas turbine (combustion turbine) or reciprocating engine, select sampling points as specified in Method 20 in Appendix A to 40 CFR Part 60.

For a boiler, select sampling points as specified in Section 5.1, Method 3, in Appendix A to Part 60. The designated representative may petition the Administrator under § 75.66 to use fewer traverse points than are specified by Method 3. The petition must include a proposed alternative sampling procedure and information demonstrating that stratification is absent at the sampling location (see the stratification test in Appendix A to Part 75, Section 6.5.6.1).

References: 40 CFR Part 60, Appendix A; Part 75, Appendix A, Section 6.5.6.1; Part 75, Appendix E, Sections 2.1.2.1 and 2.1.2.2

Key Words: Excepted methods, NO_x monitoring, Stack testing

History: First published in August 1994, Update #3 as Question 4.10; revised and renumbered in October 1999 Revised Manual

Question 26.4

Topic: Appendix E Testing and Common Stacks

Question: Two oil-fired units share a common stack. The utility wants to perform Appendix E testing and then report the emissions from the units separately. Can they test the units together at the common stack and then report the data separately for each unit?

Answer: No. In order to use Appendix E you must test and report data separately from every unit even if those units share a common stack. Perform correlation load curves for each unit separately and then report the data separately for each unit. You may test in the stack while operating one unit at a time.

References: Appendix E

Key Words: Common stack, Excepted methods, NO_x monitoring

History: First published in March 1995, Update #5 as Question 4.12; renumbered in October 1999 Revised Manual

Question 26.5 REVISED

Topic: Appendix E -- Certification Applications

Question: What must an Appendix E certification application submittal contain?

Answer: A complete Appendix E submittal must contain:

(1) A certification application form and a monitoring plan -- Including a system ID with only a DAHS component in RT 510, segment records of the NO_x correlation curve in RT 560, and data supporting the unit's status as a peaking unit.

(2) Test data -- Tests must be performed at a minimum of four evenly spaced load levels (based on heat input). For all units, testing is only required at one excess oxygen level. The data must be submitted in:

- Hardcopy, including raw data, calculations, and graphs.
- Electronic reporting format (EDR v2.1, RTs 650 - 653).

(3) Operating parameter limits -- Appendix E Sections 2.3.1 and 2.3.2 require that owners or operators of stationary gas turbines or diesel or dual-fuel reciprocating engines respectively must redetermine the NO_x emission rate-load correlation for each fuel or combination of fuels after exceeding the manufacturer's recommended range for certain operating parameters. Utilities must provide these ranges in hardcopy format.

(4) DAHS verification -- For the formula verification portion of the DAHS verification you must demonstrate that your DAHS correctly substitutes values between each of the data points on your correlation curves.

References: § 75.53(c) and (d)(2) or § 75.53(e) and (f)(2), § 75.63(b); Appendix E, Section 1.2

Key Words: Certification applications, Excepted methods, NO_x monitoring

History: First published in March 1995, Update #5 as Question 4.13; revised July 1995, Update #6; revised and renumbered in October 1999 Revised Manual

Question 26.6 REVISED

Topic: Requirements for Appendix E Testing for Gas-fired Units Burning Emergency Fuel

Question: A gas-fired peaking unit uses oil only as emergency fuel. May a utility use a petitioning process to become exempt from Appendix E testing for oil for that unit?

Answer: Yes, follow the procedures in Section 2.1.4 of Appendix E and the petition requirements in § 75.66(i).

References: § 75.66(i); Appendix E, Section 2.1.4

Key Words: Excepted methods, Gas-fired units, NO_x monitoring, SO_2 monitoring

History: First published in July 1995, Update #6 as Question 4.15; revised and renumbered in October 1999 Revised Manual

Question 26.7

Topic: Appendix E -- Missing Data

Question: For an oil and gas-fired peaking unit, is a retest of the Appendix E NO_x correlation curve needed if the unit operates at a load beyond the highest heat input rate on the curve?

Answer: A retest will not necessarily be required. If the unit operates at a higher-than-expected load, such that the hourly heat input rate is higher than the highest value on the correlation curve, the unit is considered to be in a missing data situation. When this occurs, report the NO_x emission rate for each hour of the missing data period using either one of the following methodologies:

(1) Report the higher of: (a) the linear extrapolation of the emission rate at the maximum load from the applicable correlation graph, or (b) the maximum potential NO_x emission rate, or MER (as calculated in the monitoring plan RT 530 and defined in § 72.2); or

(2) Report 1.25 times the highest NO_x emission rate on the correlation curve, not to exceed the MER. For units with NO_x controls, this option may only be used if the controls are documented (e.g., by means of parametric data) to be working during the missing data period. If the controls are not documented to be working, report the MER.

Note that if the frequency at which the hourly heat input rates exceed the current correlation curve is so high that the NO_x emission rate data availability drops below 90%, EPA may issue a notice to retest based upon Appendix E, Section 2.3. If such a retest is requested, the testing should be done at sufficiently high heat input rates to avoid a recurrence of the problem.

References: Appendix E, Section 2.3

Key Words: Excepted methods, NO_x monitoring

History: First published in December 1995, Update #7 as Question 4.16; renumbered in October 1999 Revised Manual; revised in December 2000, Update #13

Question 26.8

Topic: Appendix E -- Quality Assurance/Quality Control Parameters

Question: In the Technical Support Document for the 1995 Direct Final Rule, section M, item 7, it is explained that linear interpolation can be used to determine expected excess O_2 at load or heat input levels that fall between test levels. However, no mention is made of how to determine expected excess O_2 at levels lower than the first test level. Should the linear interpolation for excess O_2 at levels below the level 1 test use the maximum potential excess O_2 point?

Answer: No. It is not necessary to keep track of excess O_2 when the heat input is lower than the lowest heat input point. Presumably, the heat input will be less than the minimum heat input point only during start-up and shutdown conditions. The EPA intended for the quality assurance/quality control parameters to apply to the normal unit operation covered by the most recent Appendix E testing.

References: Appendix E, Section 2.3.3

Key Words: Excepted methods, Heat input, NO_x monitoring

History: First published in November 1995, Update #7 as Question 4.17; renumbered in October 1999 Revised Manual

Question 26.9 REVISED

Topic: Appendix E -- Maximum NO_x Emission Rates

Question: Regarding Appendix E maximum NO_x values, please differentiate between the maximum curve value and the maximum NO_x emission rate for the unit. Without a representative NO_x or CO_2 concentration, how should the maximum NO_x emission rate be determined?

Answer: The maximum curve value is a measured value which appears as the highest NO_x emission rate on the NO_x correlation curve developed for Appendix E estimation of NO_x. The maximum curve value corresponds to the greatest NO_x emission rate measured at the unit's highest heat input rate during Appendix E testing.

The maximum potential NO_x emission rate is a theoretical calculated value defined in § 72.2 as "the emission rate of nitrogen oxides (in lb/mmBtu) calculated in accordance with section 3 of appendix F of part 75 of this chapter, using the maximum potential nitrogen oxides concentration as defined in Section 2 of Appendix A of Part 75 of this chapter, and either the maximum oxygen concentration (in percent O_2) or the minimum carbon dioxide concentration (in percent CO_2) under all operating conditions of the unit except for unit start up, shutdown, and upsets."

Calculate the maximum potential NO_x emission rate using the maximum potential concentration of NO_x, as specified in section 2.1.2.1 of Appendix A, and the minimum carbon dioxide concentration (from historical information or diluent cap value of 5.0% for boilers or 1.0% for turbines) or maximum oxygen concentration (from historical information or diluent cap value of 14% for boilers or 19.0% for turbines).

References: § 72.2; Appendix A, Section 2.1.2.1; Appendix E, Sections 2.1.1, 2.1.6, and 2.5.2.

Key Words: Excepted methods, Missing data, NO_x monitoring

History: First published in November 1995, Update #7 as Question 4.19; revised and renumbered in October 1999 Revised Manual

Question 26.10

Topic: Appendix E -- Redetermination of Correlation

Question: Appendix E requires redetermination of the NO_x emission rate-heat input correlation whenever the unit operates for more than 16 hours outside the manufacturer's recommended range for any of the parameters that are indicative of a stationary gas turbine's NO_x formation characteristics. Do the 16 operating hours have to be successive? May they be interrupted by periods of non-operation? Does the redetermination clock reset to zero if the parameters return to normal for even one hour?

Answer: Section 2.3.1 of Appendix E states that redetermination is necessary when any of the parameters is outside the manufacturer's recommended range for ". . . one or more successive operating periods totaling more than 16 unit operating hours." This is interpreted to mean that the 16 unit operating hours must be consecutive, but may be interrupted by periods of non-operation. If the parameter(s) in question return to normal for even one hour prior to the 16th consecutive hour, then the redetermination clock resets to zero.

References: Appendix E, Section 2.3.1

Key Words: Excepted methods, NO_x monitoring

History: First published in November 1995, Update #7 as Question 4.20; renumbered in October 1999 Revised Manual

Question 26.11

Topic: Appendix E -- Redetermination of Correlation

Question: For units that co-fire gas and oil, when would redetermination of an Appendix E correlation occur if co-firing causes a unit to operate outside the recommended operating parameters for a single fuel?

Answer: It depends upon the specifics of the case. In general, the parametric limit for a particular parameter must be surpassed for both fuels before the hour of data is considered to be out of the specified limit. It then will be considered out of spec for both fuels, and will count towards triggering retesting for both fuels. Also see Question 26.10.

References: Appendix E, Section 2.3

Key Words: Excepted methods, NO_x monitoring

History: First published in November 1995, Update #7 as Question 4.21; renumbered in October 1999 Revised Manual

Question 26.12

Topic: Appendix E -- Calculation of 3,000 Hour Requirement

Question: For a simple-cycle peaking unit that may burn natural gas or oil, does the 3,000 hour threshold for conducting testing under Appendix E apply to the total operational hours for both fuels combined, or the hours that the unit burns each individual fuel.

Answer: The 3,000 hour threshold is associated with each fuel type that a unit may combust. Therefore, a unit that has burned oil for 2,000 hours and natural gas for 2,000 hours would not trigger Appendix E testing via the 3,000 hour threshold. If another unit combusts oil for 3,000 operational hours and natural gas for 1,000 hours, then the oil-fired operation would require Appendix E re-testing while combusting oil.

References: Appendix E, Section 2.2

Key Words: Excepted methods, NO_x monitoring

History: First published in October 1999 Revised Manual

Question 26.13

Topic: Comparison of QA Parameters to Defined Ranges

Question: For Appendix E, should the QA parameters be compared to defined ranges on an hourly basis and if they are out of spec then should missing data be used? Should this be done on an hourly basis or for every 15 minutes?

Answer: Compare the hourly average value of each QA parameter with its specification. Section 2.3.3 of Appendix E requires the correlation curve between NO_x emission rate and heat input rate to be re-determined when the excess oxygen level continuously exceeds the level recorded during the previous Appendix E test by more than 2% O_2 for a period of greater than 16 consecutive *unit operating hours*. Therefore, the determination of whether a particular parameter meets the specification is made on an hourly basis.

References: Appendix E, Section 2.3.3

Key Words: Excepted methods, NO_x monitoring

History: First published in October 1999 Revised Manual

Question 26.14

Topic: F-factors for Process Gas, Other Gas, and Mixtures

Question: RT 651 states that the F-factor should be consistent with the type of fuel combusted during the test and should not vary for any run or operating level in the test. What about Process Gas, Other Gas, and Mixture? The F-factors might not be different during the same run but may vary at different operating levels because of different fuel mixture ratios.

Answer: Section 2.1.2.1 of Appendix E allows a unit which burns a consistent fuel mixture to determine a heat input NO_x emission rate correlation for that consistent mixture of fuels. The Clean Air Markets Division considers a consistent mixture of fuels to be one with a composition that does not vary by more than ± 10%. For example a unit normally fires a 50 - 50 (by heat input) mixture of natural gas and #2 fuel oil. To be considered a consistent mixture under normal operations the unit should fire a mixture of between 40 - 60, gas oil and 60 - 40 gas oil. In this case, for testing purposes, use a pro-rated F-factor based on either the normal mixture of fuel (i.e., 50 - 50, heat input-weighted F-factor) or based on the actual fuel mixture used during the run. If a source burns two fuels simultaneously but does not maintain a consistent mixture, test both fuels separately and combine the emissions using the procedures for multiple fuel hours.

EPA does not recommend that you use Appendix E when you use variable fuels and/or processes. If you elect to use this method, you should consult with EPA before performing the required test. At a minimum, you may be required to submit information on the variability of the fuels and processes and test using the variable fuels and/or processes.

References: Appendix E, Section 2.1.2.1

Key Words: Excepted methods, F-factor, NO_x monitoring

History: First published in October 1999 Revised Manual

Question 26.15

Topic: Reporting of NO_x Emissions After Fuel Change

Question: My Appendix E unit was recently converted to natural gas/oil from oil. How do we report the NO_x emissions from natural gas from the time of the conversion until we are able to test and generate a NO_x curve? The quarter ended prior to the completion of NO_x testing required to establish the curve for natural gas.

Answer: In the absence of the NO_x emission rate curve required for Appendix E reporting, use the maximum NO_x emission rate (MER) for natural gas as determined from the maximum potential concentration values defined in Table 2-2 of Appendix A, Section 2.1.2.1 for your unit type. In the MER calculation, you may either: (1) use the minimum CO_2 concentration or maximum O_2 concentration (as applicable) under typical operating conditions; or (2) use the appropriate diluent cap value.

References: Appendix A, Section 2.1.2.1

Key Words: Excepted methods, NO_x monitoring, Reporting

History: First published in October 1999 Revised Manual

Question 26.16

Topic: Use of Default NO_x Emission Factor

Question: A source is building a new combined-cycle gas turbine and wants to use it in the simple cycle mode for several months while the Heat Recovery Steam Generator (HRSG) is being built. The unit will operate as a peaking unit prior to the completion of the HRSG, but will be base-loaded after the HRSG is available. May I use a default emission factor for NO_x, while the HRSG is being constructed since my NO_x CEMS will reside on a stack that will not be available until the HRSG is finished?

Answer: Yes. Until the NO_x CEMS has been certified, you may report the maximum potential NO_x emission rate (NO_x MER) from Section 2.1.2.1(b) of Appendix A to Part 75 in RT 320, using an MODC of 12. You are required to begin reporting NO_x emission data no later than 90 days after the turbine commences commercial operation.

References: § 75.4(b)(2), § 75.64(a); Appendix A, Section 2.1.2.1(b)

Key Words: Excepted methods, NO_x monitoring, Reporting

History: First published in October 1999 Revised Manual

Question 26.17

Topic: Parameters Affecting NO_x Emission Rate

Question: Our plant is installing a new oil and gas fired combustion unit. During gas-fired operation, no injection water is needed for control of NO_x emissions. For oil-fired operation we have four operational parameters to assist us in determining normal operation. One of these parameters is water-to-fuel ratio. However, when under gas-fired conditions, we have only three parameters, because water to fuel ratio is zero. Under the requirements of Appendix E, four parameters are required. Under gas-fired operating conditions, are three parameters satisfactory given the CT's dry design?

Answer: No. You must define four parameters that affect the NO_x emission rate.

References: Appendix A, Section 2.3.1

Key Words: Excepted methods, NO_x monitoring

History: First published in October 1999 Revised Manual

Question 26.18

Topic: Appendix E - Calculation of 3,000 Hour Requirement

Question: Should different types of oil (i.e., #3, #4, #6) be treated as distinct fuel types for the purpose of determining when an Appendix E unit should perform its 3,000 hour test if each fuel has its own NO_x correlation curve?

Answer: Yes. Also see Question 26.12.

References: Appendix E

Key Words: Certification tests, Excepted methods, NO_x monitoring, Recertification

History: First published in October 1999 Revised Manual

Question 26.19

Topic: Calculation of Appendix E NO_x Emission Rate Data Availability

Question: Policy Question 26.7 states: "If the NO_x emission rate data availability drops below 90%, EPA may issue a notice to retest based upon Appendix E, Section 2.3." How does EPA calculate the 90% availability?

Answer: The Agency calculates the Appendix E NO_x emission rate data availability from the most recent 2,160 hours of data or, if there are less than 2,160 hours of data in the previous three years, EPA will base the calculation on all of the data from those three years.

References: Appendix E, Section 2.3

Keywords: Excepted methods

History: First published in March 2000, Update #12

Question 26.20 NEW

Topic: Appendix E Missing Data

Question: For an Appendix E unit, what substitute data value do I report for NO_x emission rate for an hour in which the unit heat input rate is above the maximum heat input rate on the correlation curve and one or more of my monitored parameters is out of its acceptable range?

Answer: The missing data procedures for the exceedances of the maximum heat input rate on the curve take precedence over the missing data procedures for out-of-range Appendix E parameters. Therefore, use the missing data procedures described in Policy Question 26.7.

References: Appendix E, Section 2.5, Revised EDR Version 2.1 Reporting Instructions (RT 324)

Key Words: Appendix E, Missing data

History: First published in December 2000, Update #13

SECTION 27
NO_x MASS MONITORING

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Question 27.1

Topic: Capacity Factor Analyses

Question: Are statistical analyses of capacity factor or fuel usage done on a calendar year basis or might they be done for just the ozone season for Subpart H units?

Answer: For sources that report data only during the ozone season, Subpart H allows these analyses to be done on an ozone season basis.

References: § 75.71(d)(2)

Key Words: Capacity factor

History: First published in October 1999 Revised Manual

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SECTION 28
MOISTURE MONITORING

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Question 28.1

Topic: Reporting Requirements for Hourly Stack Moisture

Question: Is hourly stack moisture reporting required for all Acid Rain units?

Answer: No. Only sources using formulas that require moisture corrections are required to determine hourly moisture. This currently applies to fewer than 10% of Part 75 units. In addition, for coal and wood-fired units with formulas that require moisture corrections, moisture default values may be reported in RT 531 in lieu of reporting hourly moisture monitoring data in RT 212. See further discussion in Section 111.B.(6), "RT 212: Moisture Data," and Section 111.C.(14), "RT 531: Maximums, Minimums, Defaults, and Constants" of the EDR v2.1 Reporting Instructions.

References: § 75.57(c)

Key Words: Electronic report formats; Moisture monitoring

History: First published in October 1999 Revised Manual

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SECTION 29
LOW MASS EMITTERS

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Question 29.1

Topic: LME Methodology Start Times

Question: Can I use the LME methodology for a unit that comes on-line in the middle of a year?

Answer: Yes, provided that you begin using LME when you startup. The main requirement is that you must use the LME methodology to account for all emissions during a year (or ozone season for units subject only to OTC or Subpart H requirements), so it is acceptable to use it starting in the middle of a year if the unit did not operate until then. If your unit is operating on January 1 (or May 1 for Subpart H only units), you must start using LME then or wait until the next year.

References: § 75.19

Key Words: Low mass emissions

History: First published in March 2000, Update #12

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SECTIONS 30-32

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SECTION 33
NO_x ALTERNATIVE EMISSION LIMIT PLANS

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Question 33.1 RETIRED

Question 33.2 RETIRED

Question 33.3 REVISED

Topic: Common Stack Considerations

Question: Can an owner or operator of a unit on a common stack apply for and receive an AEL for the unit based on a methodology for apportioning emissions monitored at the common stack?

Answer: No. Each unit for which an owner or operator applies for and receives an AEL should be separately monitored by a NO_x-diluent CEMS. The unit should be separately monitored under Part 75 by no later than the commencement of the AEL demonstration period (including the operating period).

This reflects the fact that AELs are unit-specific emission limitations and are based on unit-specific demonstrations. The AEL provisions in § 76.10 are essentially a procedure for obtaining, on a unit-by-unit basis, an exception from the standard NO_x emission limitations for units that demonstrate that they cannot meet these emission limits. The owner or operator must first demonstrate that the unit cannot meet its standard NO_x emission limit during an operating period. If the unit meets certain additional requirements, an AEL demonstration period (with an interim AEL) is established. The purpose of the AEL demonstration period is to confirm that the unit cannot meet the standard emission limit and to demonstrate the minimum NO_x emission rate that the unit can achieve during long-term dispatch operation. Based on the unit's AEL demonstration period and other relevant data about the unit, a final AEL is set at the unit's minimum achievable level of emissions.

EPA intends not to accept common stack monitoring of units for which owners or operators request AEL Demonstration Periods (including interim AELs) or final AELs.

References: § 76.10

Key Words: Alternative emission limits, Common stack

History: First published in March 1996, Update #8; revised in October 1999 Revised Manual

Question 33.4

Topic: Co-firing Natural Gas or Oil

Question: When applying for a demonstration period plan or a final AEL, can a utility exclude from its analysis of NO_x emissions those periods when it was co-firing natural gas or oil with coal?

Answer: No. A coal-fired boiler is defined in 40 CFR 76.2 to be any boiler for which combustion of coal (or coal-derived fuel) is more than 50.0 percent of the unit's annual heat input in a certain calendar year (1990 for Phase I and 1995 for Phase II). For the purposes of Part 76, even a boiler that, after the pertinent base year, does not burn any coal at all will still be considered a coal-fired boiler. Moreover, the applicable emission limitations under 40 CFR 76.5, 76.6, or 76.7 apply to an affected coal-fired boiler for an entire year, regardless of the fuel mix burned during the year. Therefore, the application for an AEL demonstration period or a final AEL for the boiler must include analyses of all data, irrespective of the fuel used. Periods of firing with gas, oil, or co-firing are not excluded from this analysis.

References: § 76.2

Key Words: Alternative emission limits, Co-firing

History: First published in March 1996, Update #8

Question 33.5 RETIRED

Question 33.6

Topic: Fuel-switching as Basis for AEL

Question: Can a utility apply for an AEL demonstration period for a boiler that had been meeting the applicable NO_x limit if, after switching fuel supplies, it finds that the boiler can no longer meet the limit?

Answer: Yes. EPA will consider an application in which the utility establishes all of the following for that boiler:

(1) There is a direct, significant relationship (which the utility quantifies) between the fuel types used and the NO_x emission rates achieved at that particular boiler;

(2) The emission limit cannot be achieved by reoptimizing the firing system to minimize NO_x emissions;

(3) The boiler's LNB system is designed to meet the emission limit over a range of fuel types and that the fuel type to which the boiler has switched is within that range;

(4) The utility provides an acceptable explanation for switching fuel supplies (e.g., fuel switching for other environmental benefits or switching because of unavailability of current fuel supply are examples of acceptable explanations); and

(5) The requirements of 40 CFR 76.10 are satisfied.

References: § 76.10

Key Words: Alternative emission limits, Fuel switching

History: First published in March 1996, Update #8

Question 33.7

Topic: Operational Problems as Basis for AEL

Question: If operating the boiler or the NO_x control equipment under the conditions upon which the design of the NO_x emission control system was based causes slagging, tube wastage or burner deterioration, may the owner or operator deviate from those operating conditions to alleviate such problems and still receive an AEL?

Answer: No. Under § 76.10(d)(7) the designated representative of the affected unit applying for an AEL demonstration period must certify that "the owner(s) or operator operated the unit and the NO_x emission control system during the operating period in accordance with: Specifications and procedures designed to achieve the maximum NO_x reduction possible with the installed NO_x emission control system or the applicable emission limitation in § 76.5, § 76.6, or § 76.7; the operating conditions upon which the design of the NO_x emission control system was based; and vendor specifications and procedures." This requirement reflects the fact that operating conditions for a boiler and NO_x control equipment are carefully considered and agreed upon by both the vendor supplying the NO_x control equipment and the utility purchasing that equipment. Further, operation of NO_x control equipment under agreed-upon operating conditions is verified in the equipment testing period.

References: § 76.5, § 76.6, § 76.7, § 76.10(d)(7)

Key Words: Alternative emission limits, Operational problems

History: First published in March 1996, Update #8

Question 33.8

Topic: Inability to Install a Control System Designed to Meet the Emission Limit

Question: How can a utility show that it has installed a control system that was designed to meet the applicable emission limit in Attachment B to the Petition for an AEL Demonstration in cases when no vendor was able to provide such a system?

Answer: 40 CFR 76.10(a)(2)(ii) requires that NO_x control equipment on a boiler applying for an AEL be "designed to meet the applicable emission limitation in §§ 76.5, 76.6, or 76.7." However, EPA will consider an application in which the utility establishes all of the following:

(1) The utility solicited bids for a LNB system designed to meet the applicable limit;

(2) It described in its solicitation the range of operating conditions (including fuel supply and load dispatch pattern) that it expected to experience while operating to comply with the applicable emission limit;

(3) It received three or more responses from reputable, nationally recognized vendors that identify the lowest emission rate that could be achieved with their equipment;

(4) None of the identified emission rates in (3) was equal to or less than the applicable limit;

(5) The utility installed the control equipment, available for purchase, that would produce the lowest emission rate amongst the emission rates identified in (3);

(6) The utility operated the control equipment installed in (5) to produce the lowest emission rate identified with this control equipment in (3) and the operating conditions were within the range of operating conditions in (2); and

(7) The requirements in 40 CFR 76.10 are met.

References: § 76.5, § 76.6, § 76.7, § 76.10(a)(2)

Key Words: Alternative emission limits, Vendor guarantees

History: First published in March 1996, Update #8

Question 33.9

Topic: AEL Demonstration Versus Boiler Load Profile

Question: A boiler is unable to meet the applicable limit at high loads but is able to meet the limit at lower loads. Can the AEL demonstration be based solely on periods of high load operation?

Answer: No. Under § 76.10(b)(3), during the demonstration period, the utility must determine "the minimum NO_x emissions rate that the specific unit can achieve during long-term load dispatch operation."

References: § 76.10(b)(3), § 76.10(e)(8)

Key Words: AEL demonstration period, Boiler load profile

History: First published in March 1996, Update #8

Question 33.10

Topic: AEL and NO_x Apportionment Methodologies

Question: Can I use a NO_x apportionment for an AEL demonstration or to satisfy an AEL?

Answer: No. AELs are not covered by this policy.

References: § 76.10

Key Words: Alternative emission limits

History: First published in October 1999 Revised Manual

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SECTION 34
EARLY ELECTION PLANS

RETIRED

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KEY WORD INDEX

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Mecalf Building, 1520 E Sixth Avenue
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Mr. Eric Kopczynski . . . . (406) 247-4453
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APPENDIX B
CORRESPONDENCE

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Appendix B: Correspondence

Letter on Recertification

August 20, 1993

Ms. Cecilia Mijares
U.S. EPA Region 5
Air and Radiation Divisions (AE-17J)
77 West Jackson Boulevard
Chicago IL 60604

Dear Ms. Mijares:

Electric Energy, Inc. (EEI) is planning to replace the orifices in the sample probes for the continuous Emissions Monitoring System (CEMS) with one that is not an exact duplicate. It will, however, provide the same concentration of diluted sample to the analyzers. EEI request confirmation that replacement of the sample orifice in the CEMS dilution probe will not require re-certification of the monitors.

EEI has the dilution type CEM system. This system extracts a sample of gas from the stack and dilutes it with air at a ratio of 150:1. An orifice is used to meter the stack gas sample flow to the mixing chamber. Instrument air is added until the 150:1 dilution ratio is achieved.

EEI installed the system this year and went through field certification in June. Based on recent operating experience, EEI believes that changing the stack gas sample orifice to a smaller one will increase the reliability of the system. We have found that our current orifice does not respond as desired to small changes in air from the air supply. The new orifice will be more tolerant to air supply fluctuation and, therefore, should provide more reliable readings. This smaller orifice will still provide a 150:1 dilution ratio, but will require less instrument air to do it. Because the stack gas sample dilution ratio will remain constant, the operating range of the analyzers will not be affected.

In the dilution type system, calibration gas is introduced ahead of the stack gas orifice. The calibration gas is drawn through the orifice and diluted exactly the way a stack gas sample would be. The analyzers measure the concentration in the diluted sample. The Data Acquisition System (DAS) takes that analyzer value, multiplies it by 150 and compares it to the known bottle value. When EEI changes the orifice to the smaller one and reduce the instrument air accordingly to maintain the 150:1 dilution ratio, EEI will perform a complete calibration gas linearity check to verify that the dilution ratio is maintained.

In summary, EEI believes that changing the sample orifice in the dilution probe does not affect the ability of the system to measure SO_2, NO_x, or CO_2 concentrations and should not require complete recertification since the same dilution ratio is maintained. EEI will perform a calibration gas check of the system using low, mid and high concentrations of calibration gas. This check will confirm that stack gas concentrations will be accurately measured.

At your earliest convenience, please provide confirmation that re-certification is not required so this improvement can be implemented in our system. If you have any questions, please contact Mr. Bruce Parker at (618) 543-7531, extension 458.

Sincerely,

{signed}
William H. Sheppard
Plant Manager

EPA's Response:

September 13, 1993

William H. Sheppard
Plant Manager
Electric Energy, Incorporated
P.O. Box 165
Joppa, Illinois 62953

RE: Replacement of Sample Orifice on Acid Rain CEMS at Joppa Steam Plant, Joppa, Illinois

Dear Mr. Sheppard:

This is in response to your letter of August 20, 1993. The United States Environmental Protection Agency (USEPA) has considered your request for guidance on whether the proposed replacement of sample orifices within your acid rain continuous emission monitoring system (CEMS) would require recertification.

Specifically, Electric Energy, Inc. (EEI) conducted field certification testing in June 1993 on CEMS installed on units 1-6 at the Joppa Steam Plant. Based on the current performance of these CEMS, you believe that changing the stack gas sample orifice to a smaller one will increase the CEMS tolerance to small fluctuations in air from the air supply, and that therefore increase the CEMS reliability. By adjusting the supply of air to compensate for the smaller size of the replacement orifice, you will maintain the CEM's current 150:1 dilution ratio. Because the calibration gas physically passes through this stack gas sample orifice component of the CEM, you believe that a calibration gas linearity check will verify that the 150:1 dilution ratio is maintained once you have installed the replacement orifice and adjusted the air supply.

After reviewing all the information provided in your letter, USEPA agrees that a successful calibration gas linearity check will confirm that the replacement orifice and the adjusted air supply have not changed the CEMS' measurement capability. Furthermore, because you have indicated that these proposed changes would increase the sensitivity of the CEMS, we believe that a successful 7-day calibration error test will confirm whether the replacement orifice and the adjusted air supply have changed the CEMS' measurement stability.

Therefore, if you proceed to implement these proposed changes by installing replacement orifices, USEPA would require that you reconduct the linearity check and the 7-day calibration error test for each affected CEMS. Those tests will confirm that the dilution ratios and resulting concentrations have not changed from the values determined in the June 1993 field test. Please submit the test results as a revision to the certification application to both the USEPA Region 5 and the Illinois Environmental Protection Agency.

If the CEMS fails either the linearity check or the 7-day calibration error test, then EEI would be required to re-conduct all the field certification tests, and submit a new certification application. USEPA notes that "recertification" is not the appropriate term for this case, since the CEMS have not yet been certified.

If you have any questions, please contact Cecilia Mijares of my staff, at (312) 886-0968.

Sincerely Yours,

{signed}
Cheryl Newton, Chief
Grants Management and Program
  Evaluation Section
Regulation Development Branch
Air and Radiation Division

cc: Ms. Margaret Sheppard
USEPA Acid Rain Division

Mr. Frederick Smith
Illinois Environmental Protection Agency

Letter Concerning Submission of Certification Test Results to Phase I Designated Representatives in EPA Region VII

dated October 1, 1993

{Address of DR}

Dear {name of DR}:

Over the past several months, the Region 7 Acid Rain Program continuous emission monitoring team has participated in a number of pre-test meetings and on-site test activities. We've observed much confusion about how certification results are to be submitted; whether in a hardcopy report, on magnetic media (diskette) or on both formats. This letter is intended to clarify exactly what information, and in what format, test results are to be submitted to the regional office.

For monitors to quality for certification, Part 75 requires "magnetic" submission of all certification test results in the format specified by the Electronic Data Reporting (EDR) instruction, Version 1.1 (copy enclosed). In particular, the certification data must be submitted on an IBM compatible 3-1/2" or 5-1/4" high density floppy disk. Furthermore, each electronic report submission must be a single ASCII flat file composed of variable length records with each Record Type exactly following the format specified in the EDR instructions. It is important to note that spreadsheet and database files neither meet the requirement of being ASCII flat files nor do they satisfy the format specifications in the EDR instructions.

So far, Region 7 has received only one diskette containing certification test data. The diskette contained a number of spreadsheet files (non-ASCII readable) and only one ASCII-readable file of minute-by-minute test results of unknown origin. The only ASCII-readable file was not in the format described in the EDR instructions. As a consequence the diskette was unreadable by EPA's certification results review software and could not be processed.

Besides meeting the format specified in the EDR instructions, each submitted diskette must contain the information listed in EDR Tables 3 (Monitoring Plan Information) and 4 (Test Information), along with Table 2, Record-type 100 (Facility Information). The certification test results data file must be sorted in facility-unit-component-test data order, i.e.,

Rec 100	Facility information
Rec 500	Monitoring plan unit definition table...Unit 1
Rec 501	Monitoring plan common stack definition table...Unit 1
Rec 510	Monitoring system component table...Component A
Rec 600-631	Test information...Component A
Rec 510	Monitoring system component table...Component B
Rec 600-631	Test information...Component B
	.....etc.....
Rec 500	Monitoring plan unit definition table...Unit 2
Rec 501	Monitoring plan common stack definition table...Unit 2
Rec 510	Monitoring system component table...Component A
Rec 600-631	Test information...Component A
Rec 510	Monitoring system component table...Component B
Rec 600-631	Test information...Component B
	.....etc.....

Enclosed is an "example" hardcopy printout containing hypothetical data showing how the ASCII file might look if properly constructed. As a clarification to the EDR instructions, you may exclude Record Type 520 (formula table) from the certification results data file. Likewise, if not seeking approval for an alternative monitoring system, Record Types 630 (alternative monitoring system data) and 631 (alternative monitoring system results and statistics) are not necessary. We request that you include two copies of the certification results diskette, one for the regional office and one for the Acid Rain Division, with your certification application(s).

The region also requires, as part of our standard operating procedure, a hardcopy report of all test results, calculations, calibration data, plant operating data, and other information described in the enclosed report outline. Much of this information cannot easily be put on or read in electronic format and is only useful in hardcopy format. Additionally, the hardcopy report provides the regional office with a permanent record of the certification test results and other important baseline information. We request, in addition to the two copies provided to Region 7, that you send a copy of the hardcopy results to your respective state and local air pollution control agencies.

To avoid any unexpected surprises in preparing the electronic data file, we recommend that you consult with your data acquisition and handling system vendor, your testing contractor, and other utility staff to ensure that you have a mechanism to generate the required data file in the appropriate format. As previously mentioned in our September 2, 1993 letter, your certification application cannot be considered complete until you submit all elements of the application, including the hardcopy certification test results report, the electronic certification test results data file and the data acquisition and handling system verification. We hope you find the enclosed information useful. In the meantime, if you have any question about the certification process, please give me a call at (913) 551-7622.

Sincerely,
{signed}
Jon Knodel
Air Permits Section

Memorandum on Protocol Gas Concentration Adjustments

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

August 29, 1996

OFFICE OF
AIR AND RADIATION

MEMORANDUM

SUBJECT: Implementing Protocol Gas Concentration Adjustments

FROM: Acid Rain Division

TO: Part 75 Affected Sources

Part 75 affected sources should follow the guidance in the July 24, 1996 memorandum from Andrew Bond (attached). This memorandum is also available on the TTN. In addition to following the July 24 memorandum, the following Part 75-specific guidance should be followed:

! Do not retrospectively correct test results from tests conducted with affected gases or resubmit emissions data reported from monitors calibrated with affected gases.

! Prior to January 1, 1997 (after which all calibration gases must be based on corrected standards), we recommend that utilities check the SO_2 calibration gases used to calibrate the reference method monitor before performing a relative accuracy test audit. Verify that the SO_2 calibration gases for the reference method monitor are consistent (adjusted or not adjusted) with the SO_2 calibration gases used to calibrate the stack CEMS. If necessary, make adjustments so that all of the SO_2 calibration gases are corrected to the accurate standard.

! Any questions may be directed to the appropriate USEPA Regional Office or Acid Rain Division contact.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
NATIONAL EXPOSURE RESEARCH LABORATORY
RESEARCH TRIANGLE PARK, NC 27711

July 24, 1996

OFFICE OF
RESEARCH AND DEVELOPMENT

MEMORANDUM

SUBJECT: Guidance for SRMs and NTRMs Certified by NIST between 1989 and 1996

FROM: Andrew E. Bond, Acting Chief
Quality Assurance Branch (MD-77B)
AMRD/National Exposure Research Laboratory
Research Triangle Park, NC 27711

TO: Suppliers of Protocol Gases

The National Institute of Standards and Technology (NIST) has informed us that they are adjusting the SO_2 concentrations in the Standard Reference Materials (SRMs) and the NIST Traceable Reference Materials (NTRMs) that were certified between 1989 and May 31, 1996. The adjustments are required as the result of an intercomparison between the traditional titration method and a gravimetrically prepared standard.

We are aware that some of these SRMs and NTRMs have been used in the past or may be used in the future to certify Protocol Gases either directly or through the use of Gas Manufacturer's Intermediate Standards (GMISs) traceable to these SRMs and NTRMs. No later than September 1, 1996 all new Protocol Gases produced or sold are required to be based upon the adjusted SRM/NTRM value. This includes gases produced using GMISs. In addition, Protocol Gases produced using adjusted SRM/NTRMs should be tagged with a code "R" before the SRM number to indicate that the adjustment has already been made (i.e., "SRM 1693a" would be changed to "SRM R1693a" on the Protocol Gas certification/cylinder labels).

Some of the Protocol Gases presently in use or previously used in conformance to 40 CFR Parts 58, 60, 61 and 75 may also require an SO_2 concentration "adjustment." This includes gases used for stack CEMS and reference method testing. It is acceptable to re-issue certificates and cylinder labels with the corrected gas values. If this approach is followed, the new certificate and cylinder labels should be tagged with a code R in the SRM number to indicate that the adjustment has been made.

We are aware that issuing new certificates and labels for affected Protocol Gases could be costly and time consuming. Therefore, it is also acceptable to EPA if the owners of Protocol Gases hand-correct their certificates and cylinder labels. If this approach is followed, owners of Protocol Gases should attach documentation to the certificate indicating the unadjusted concentration, the adjustment factor, and the new adjusted concentration (this may include a letter from the supplier of the Protocol Gas indicating the "adjustment factor" they should use). A sample standard form and a blank form for making these hand corrections are attached. The EPA regulatory units concerned with 40 CFR Parts 58, 60, 61 and 75 have concurred with this approach.

Protocol Gas users must implement the adjustment no later than January 1, 1997. Each EPA regulatory unit may issue additional guidance about how this adjustment will affect their program.

We would appreciate it if you would notify your Protocol Gases users of the required "adjustment" to their SO_2 concentration. Please feel free to include a copy of this letter with your correspondence.

If you have questions please feel free to contact Ms. Avis Hines of my staff at 919-541-4001 or by FAX 919-541-7953.

Attachments

cc: Avis Hines, MD-77B
Bill Mitchell, MD-77B
Ross Highsmith, MD-78A
Jim Vickery, MD-75
John Silvasi, MD-14
John T. Schakenbach, 6204J

SAMPLE STANDARD FORM

EPA Cylinder Gas
SO_2 Concentration Adjustment

Gas Cylinder Data:

Gas Supplier:	Gas Vendor
Cylinder No.:	XXX123
Certification Date:	7/25/96
Expiration Date:	7/25/99
Type of Cylinder: (P=protocol, G=GMIS, N=NTRM, S=SRM)	P
Original SO_2 concentration, $C(SO_2)_{ori}$:	90.81 ppm
Corrected SO_2 concentration, $C(SO_2)_{cor}$: $C(SO_2)_{cor} = C(SO_2)_{ori} *F_{cor}$	92.70 ppm

Gas Standard* Data:

Standard No.:	SRM-0000
Corrected Standard No.:	SRM-R-0000
Cylinder No.:	xxx-456
Expiration date:	7/20/97
Original concentration of the standard, S_{org}:	259.8 ppm
Correct concentration of the standard, S_{cor}: (from NIST table)	265.2 ppm
Correction factor, $F_{cor} = S_{cor}/S_{org}$:	1.021

Signature: ________________________________ Date: ___________________

* SRMs or NTRMs

EPA Cylinder Gas
SO_2 Concentration Adjustment

Gas Cylinder Data:

Gas Supplier:
Cylinder No.:
Certification Date:
Expiration Date:
Type of Cylinder:
(P=protocol, G=GMIS, N=NTRM, S=SRM)
Original SO_2 concentration, $C(SO_2)_{ori}$:
Corrected SO_2 concentration, $C(SO_2)_{cor}$:

$$C(SO_2)_{cor} = C(SO_2)_{ori} * F_{cor}$$

Gas Standard* Data:

Standard No.:
Corrected Standard No.:
Cylinder No.:
Expiration date:
Original concentration of the standard, S_{org}:
Correct concentration of the standard, S_{cor}:
(from NIST table)
Correction factor, $F_{cor} = S_{cor}/S_{org}$:

Signature: ________________________________ Date: ___________________

* SRMs or NTRMs

Letter on Early Election and Common Stack Continuous Emissions Monitoring

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

August 9, 1996

OFFICE OF
AIR AND RADIATION

Mr. Michael Cashin
Environmental Engineer
Minnesota Power
30 West Superior Street
Duluth MN 55802-2093

Re: Early Election and Common Stack Continuous Emissions Monitoring

Dear Mr. Cashin:

As I indicated in my letter of July 24, 1996, I am writing to follow up and respond to your remaining questions to which I have not yet responded. Specifically, you have raised questions concerning whether or not the provisions of §75.17(a)(2)(i) through (iii) apply to units that send in early election plans under 40 CFR 76.8. You indicated that Minnesota Power is interested in knowing about possible options where it might early elect all units sharing a common stack and then monitor NO_x with a CEMS on the common stack.

In all cases, the early election units may be monitored individually for NO_x emission rate in lb/mmBtu, under §75.17(a)(1) or (2)(iii)(a) (where all units on the common stack are affected units) or (b)(1) (where one or more units on the stack are nonaffected units). It is not necessary to install a flow monitoring system on each unit in order to determine the NO_x emission rate. As discussed below, the early election units may instead be monitored at the common stack only under certain circumstances.

EPA notes that part 76 states that each individual early election unit must demonstrate that it meets the Phase I NO_x emission limitation each year, starting from the effective date of the early election through December 31, 2007. In fact, a unit's early election plan will be terminated if the unit cannot make this demonstration (§76.8(e)(3)(i); 59 FR 13538, 13561 (March 22, 1994)). The purpose of this special requirement for early election units is to avoid allowing a unit to be grandfathered until 2008 from a stricter, revised Phase II NO_x emission limitation without that unit providing an offsetting environmental benefit through early compliance with the Phase I NO_x emission limitation (59 FR 13561). Otherwise, the environment could receive more NO_x emissions than if the unit had not early elected.

The restrictions on early election unit averaging are consistent with this approach. Under part 76, early election units are not allowed to participate in an emission averaging plan before the year 2000. An early election unit may participate in an emission averaging plan in the year 2000 or thereafter. However, the emission limitation included for that unit in the calculation for determining if there is group compliance with the plan is the revised Phase II emission limitation, if a revised limitation is issued under section 407(b)(2) of the Act (§§76.8(a)(5) and 76.11(d)(1)(ii)(A)). These restrictions on averaging for early election units prevent utilities from using the early reductions at such units in lieu of reductions that would otherwise have to be made at Phase I units prior to 2000 or Phase I and Phase II units starting in 2000 (59 FR 13560-61).[1] In analyzing the impact of averaging plans, EPA assumed that individual early election units would meet the Phase I emission limitations (59 FR 13561). This assumption reflects the requirement, noted above, that the early election be terminated for any individual unit failing to meet the Phase I emission limitation through 2007.

If units share a common stack and the NO_x emission rate is measured only on the common stack, it is not possible, without additional information, to determine if each individual unit actually met the Phase I NO_x emission limitation. For example, if there is a group of Phase II units using a common stack, where only one unit has emission controls installed and all units are early elected, it is physically possible for the group of units to meet the Phase I NO_x emission limitation at the common stack on an average basis without each individual unit meeting the limitation. Thus, monitoring on the common stack with a stack NO_x CEMS may not ensure compliance with the requirement in § 72.8 [sic; § 76.8] that each individual early election unit meet the Phase I emission limitation. For this reason, when the early election provisions were first promulgated, EPA stated that there are two options for monitoring such units: "either installing separate CEMs for each early elected [unit's] duct, or install[ing] one CEM in the common stack, provided the NO_x emission rates are apportioned in a manner approved by the Administrator." Comment and Response Document for March 22, 1994 rule at 126 (February 1994).[2]

Sections 75.17(a)(2) and 75.17(b) address, for Phase I and Phase II units in general, the conditions under which common stack NO_x monitoring may be used. However, those sections do <u>not</u> address under what circumstances the owner or operator of prospective early election units can use common stack monitoring to meet the special requirement, under §76.8(e)(3)(i), of demonstrating that each such unit individually meets the Phase I NO_x emission limitation. This is reflected in the form issued by EPA implementing the Phase I NO_x regulations, which requires each prospective early election unit to specify in its NO_x compliance plan that the unit itself will meet the Phase I emission limitation for wall-fired or tangentially fired boilers. The form expressly bars a unit selecting early election from also selecting one of the monitoring options otherwise available under §75.17(a)(2)(i)(A) or (B). <u>See</u> Instructions for NO_x Compliance Plans for Phase I Permit Application at 2 (March 1994).

Under §76.8(d)(1), EPA will only approve early election plans that comply with the requirements of §76.8. Consequently, EPA will not approve early election plans under circumstances where the owners or operators will not be able to make the demonstration required under §76.8(e)(3)(i).

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1 This also prevents emission reductions made at nonearly election units from being substituted for making reductions at early election units.

2 In the first sentence of the response to comment, EPA stated that "[compliance demonstration for early election units is no different than compliance demonstration for other affected units." <u>Id.</u> This summary statement was incorrect on its face since, for example, early election units, unlike other affected units, must demonstrate individual unit compliance and are barred from averaging prior to 2000 (§76.8(a)(5) and (e)(3)(i)).

EPA will approve early election plans for qualified units that are individually monitored for NO_x and thereby have the ability to make this demonstration. EPA will consider approving plans for prospective early election units with common stack NO_x monitoring only in either of the following circumstances:

(1) The designated representative may petition the Agency for approval of a method for apportioning the NO_x emission rate measured in the stack by a common stack monitor among the units on the stack. The apportionment methodology must ensure the complete and accurate estimation of NO_x emission rate for each unit. EPA notes that these requirements may be difficult to meet. If EPA approves an apportionment method as consistent with the requirements of §75.17(a)(2)(i)(C) or (b)(2), common stack NO_x monitoring may be used in conjunction with the approved apportionment method.

(2) If every unit sharing the common stack is an early election unit and the demonstrations described below are made, the utility may monitor for NO_x on the common stack and show that the group of units on the stack meets on an average basis the strictest of the NO_x emission limitations applicable to one or more of the units. In order to ensure that each unit is meeting the applicable Phase I NO_x emission limitation individually, a utility must demonstrate that:

(A) each of the units using the common stack has installed low NO_x burner technology (LNBT) with a performance guarantee that the unit will meet the Phase I limitation; and

(B) the performance guarantee has been met for each unit. In making this demonstration, the utility must provide: the performance data and resulting report for each unit from the acceptance testing required under the contract with the LNBT vendor.

If you have further questions, you may contact me at (202) 233-9163.

Sincerely,

[signed]
Margaret A. Sheppard
Environmental Scientist
Acid Rain Division

cc: Constantine Blathras, EPA/Reg. 5
Dwight Alpern, EPA/ARD

Letter on NO_x Monitoring for Common Stack Early Election Units

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

August 19, 1996

OFFICE OF
AIR AND RADIATION

R. James Gronquist, P.E.
Designated Representative
Jamestown Board of Public Utilities
92 Steele Street P.O Box 700
Jamestown, NY 14702-0700

Re: Jamestown Board of Public Utilities Title IV NO_x Early Election Plan

Dear Mr Gronquist,

I have received your July 8, 1996 letter concerning early election and common stack continuous emissions monitoring at boilers #9, #10, #11, and #12 at your Samuel A. Carlson Generating Station. According to your letter, boilers #9 and #12 share a common stack and boilers #10 and #11 share a separate common stack. Your letter also indicates that you wish to apply for early election for all four units under the provisions of 40 CFR 76.8. In this letter, you requested clarification on several issues concerning qualification of these units for early election.

Part 76 requires the owner or operator of units that early elect to demonstrate that each individual early election unit meets the applicable Phase I NO_x emission limitation. See 40 CFR 76.8(e)(3)(i). EPA believes that the data from a common stack alone will not generally be sufficient to demonstrate that each unit emitting to that common stack meets the Phase I emission limitation and thus qualifies for an early election plan. EPA's recommended option is to monitor NO_x emissions at the unit level. However, based on your letter, EPA understands that this is not feasible at your facility. Thus EPA provides the following, Jamestown may monitor at the common stack and meet the most stringent Phase I emissions limitation applicable to any of the units sharing the common stack beginning each year from 1997 through 2007. Jamestown must also demonstrate that each individual unit meets the NO_x emission limitation by providing the following data:

1. For a unit with installed low NO_x burners that are guaranteed to meet the applicable Phase I NO_x emission limitation, a copy of the performance guarantee, for the low NO_x burners installed or being installed, that the individual unit will meet the applicable limitation and a demonstration that the performance guarantee has been met for the unit. In making this

demonstration, you must provide the performance data and resulting report for the unit from the acceptance testing required under the contract with the low-NO_x-burner vendor.

2. For a unit with installed low NO_x burners that are not guaranteed to meet the applicable Phase I NO_x emission limitation, post-low-NO_x-burner-installation emission data showing that the unit meets the Phase I emission limitation (in lieu of the information in paragraph 1 above). In making this demonstration, you must include at least 720 operating hours of monitored NO_x emission data either: (i) at the common stack from a certified continuous emission monitoring system (CEM) (in accordance with 40 CFR Part 75) when the unit is the only boiler emitting to the common stack; or (ii) at the duct of the unit using EPA reference method 7E in Appendix A of 40 CFR Part 60. You must also show that this data was obtained during a period representative of normal operation of the unit. We understand that the low NO_x burners on boilers #9 and #10 were not guaranteed to meet the Phase I emission limitation. EPA will evaluate the data that you submit for these units to determine whether each unit meets the Phase I emission limitation during normal operation.

EPA notes that, under the final NO_x rule, early election units cannot participate in an averaging plan in Phase I and can participate in an averaging plan in Phase II only if any revised Group 1 emission limitation is used for the unit in determining compliance with the averaging plan. See 40 CFR 76.8(a)(5) and 76.11(d)(1)(ii)(A).

Finally, if you wish to elect only one of the two units at a common stack, the only monitoring options available for that unit are to monitor with a certified CEM at the individual early election unit or to monitor with a certified CEM at the common stack with an EPA approved apportionment method. Otherwise, the unit cannot be approved for early election.

Before EPA can complete the processing of your early election plan, you must submit (consistent with paragraphs 1 and 2 above): at least 720 operating hours of data from boilers #9 and #10 demonstrating that they meet the Phase I emission limitation; and the performance guarantee for the low NO_x burners on boiler #11. In addition, any approval of the early election plan will have to be conditioned on receipt of the performance guarantee for low NO_x burners on boiler #12 and the demonstrations of achievement of the guarantees that boilers #11 and #12 meet the Phase I emission limitation. In order to provide more certainty concerning the status of these boilers under any conditionally-approved early election plan, the information on which the plan will be conditioned should be provided as soon as possible. If you have any further questions, please contact Kevin Culligan of my staff at (202) 233-9172.

Sincerely,

[signed]
Larry Kertcher, Branch Chief
Source Assessment Branch

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APPENDIX C
MISCELLANEOUS

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APPENDIX C: MISCELLANEOUS

Summary of Field Study on Reference Methods 6C, 7E, and 3A

A collaborative evaluation of Reference Methods (RM) 6C, 7E, and 3A was recently done at the Big Rivers Electric Corporation facility in Sebree, Kentucky. Two RM sampling techniques (dry-basis extractive and wet-basis dilution) were compared side-by-side for 72 concurrent sample runs; each run was 30 minutes in duration. Four test teams participated in the study, with two teams using the dry-basis method and two teams using the dilution method.

Three gases (SO_2, NO_x, and CO_2) were measured, and each RM measurement system was calibrated before and after each test run. Methods 3A, 6C, and 7E were precisely followed for the dry-basis tests. For the dilution tests, calibration techniques and run validation procedures similar to the procedures recommended in Section 21 of this policy document were used. In 36 of the test runs, the dry-basis and dilution RM systems were calibrated against the same set of calibration gases ("A-Group" gases). In the other 36 runs, each test team used its own calibration gases ("B-group" gases).

The results of the Big Rivers study generally show good agreement and reproducibility between the wet and dry RM measurement techniques. However, it is quite clear from the results that the wet-basis readings were consistently higher than the corresponding dry-basis readings. For the three gaseous species measured, the dilution extractive RM systems gave concentration readings higher than the dry-basis RM systems, approximately 92 percent of the time. The wet-basis readings averaged about 3 to 5% higher than the dry basis readings, irrespective of whether the "A" or "B" Group gases were used for the calibrations.

The results of the Big Rivers study are presented in the document entitled, "A Collaborative Field Evaluation of EPA Test Methods 6C, 7E and 3A" (Prepared for EPA under Contract No. 68-D2-0163 by Entropy, Inc.; Research Triangle Park, NC; March 1994).

History: First published in March 1995, Update #5

Quick Reference Guide To Flow Span

Definitions:

Maximum Potential Velocity (MPV) - represents the maximum stack gas velocity for a given unit or stack. It can be determined either through velocity traverse testing or a formula calculation. It is expressed in units of standard feet per minute (sfpm), wet basis.

Maximum Potential Flow Rate (MPF) - is the maximum stack gas flow rate in standard cubic feet per hour (scfh), wet basis. It is used for missing data purposes and to set the flow rate span value.

Calibration Units - refers to the actual units of measure used in daily calibration error testing of a flow monitor (sfpm, ksfpm, scfm, kscfm, scfh, kscfh, acfm, kacfm, acfh, kacfh, inH2O, mmscfh, mmacfh, afpm, kafpm).

Calibration MPF - is the maximum potential flow rate expressed in calibration units. This value is not calculated for differential pressure (DP) type flow monitors.

Calibration Span Value - is a calculated value which is used to determine the zero-level and high-level reference signal values for calibration error testing. It ensures that calibration tests are performed at levels that are representative of the actual values that the monitor is expected to be reading. It is expressed in calibration units

Flow Rate Span Value - is a calculated value used to set the full-scale reporting range of a flow monitor, in scfh.

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Full-Scale Range - represents the largest value that a particular scale on the instrument is capable of measuring. It is a result of the design and construction (and subsequent modification) of the monitor itself. The full-scale range used for daily calibration error tests is expressed in calibration units. The full-scale range used for flow rate reporting is expressed in units of scfh, wet basis. The full-scale range must be greater than or equal to the corresponding span value.

Determination of Important Values:

! **MPV**

Test Results - MPV may be determined based on velocity traverse testing. If this method is chosen, use the highest average velocity measured at or near the maximum unit operating load. (Part 75, Appendix A, Section 2.1.4.1)

Formula - MPV may be determined using Equation A-3a or A-3b in Part 75, Appendix A, Section 2.1.4.1.

Historical Data - MPV may be determined using historical data. If this method is used, the historical data must include operation at the maximum load level and the MPF must represent the highest observed flow rate. (Part 75, Appendix A, Section 2.1.4.3.)

! **MPF**

Multiply MPV (in sfpm, wet basis) by the inside cross sectional area (in square feet) of the flue at the flow monitor location. Then multiply this value by 60 to convert to scfh on a wet basis. That is:

$$MPF(scfh_{wet}) = MPV(sfpm_{wet}) \text{ x } A(ft^2) \text{ x } 60(m/h)$$

Round the MPF upward to the next highest multiple of 1000 scfh

! **Calibration MPF (Non-DP type monitors, only)**

Multiply MPF (in scfh, wet basis) by the appropriate conversion factors to convert to calibration units. That is:

$$\text{Calibration MPF (cal units)} = MPF(scfh_{wet}) \text{ x [Conversion to cal units]}$$

This value should not be calculated if a DP type flowmeter is used.

! **Calibration Span Value (Non-DP type monitors)**

Convert MPV into the units that will be used for the daily calibration test. Then multiply this value by a factor no less than 100 percent and no greater than125 percent and round up the result to no less than 2 significant figures. In other words, the rounded result should have at least 2 significant figures and should follow engineering convention by not having more non-zero figures than the precision of the measured values used in the calculation. (Part 75, Appendix A, Section 2.1.4.2) That is:

$$\text{Calibration Span Value (cal units)} = MPV(sfpm_{wet}) \text{ x [Conversion to cal units] x [Multiplier 1.00 to 1.25]}$$

or

$$= \text{Calibration MPF (cal units) x [Multiplier 1.00 to 1.25]}$$

! **Calibration Span Value (DP type monitors)**

For DP-type monitors, multiply the MPV (sfpm) by a factor no less than 1.00 and no greater than 1.25. Convert the result from sfpm to units of actual feet per second (afps). Then, use Equation 2-9 in Reference Method 2 (40 CFR 60 Appendix A) to convert the actual velocity to an equivalent delta P value in inches of water. Retain at least two decimal places in the resultant delta P, which is the calibration span value.

! **Flow Rate Span Value (All flow monitors)**

Calculate the flow rate span value as follows:

$$\text{Flow Rate Span Value } (scfh_{wet}) = \text{MPF } (scfh_{wet}) \times [\text{Multiplier } 1.00 \text{ to } 1.25]$$

Round the flow rate span value upward to the next highest multiple of 1000 scfh

! **Full-Scale Range for Reporting**

Select the full-scale range for reporting hourly flow rates so that the majority of readings obtained during normal operation will be between 20 and 80 percent of full-scale (Part 75, Appendix A, Section 2.1). The full-scale range must be equal to or greater than the flow rate span value.

Reporting of Important Monitoring Plan and Quarterly Report Values[1]:

Value	Hardcopy Monitoring Plan	Quarterly Report (Record Type/Column)	Units
MPV	Table D-2 (if calculated) or attached method explanation and calculations (if determined from testing)	Not reported	sfpm, wet
MPF	Table D-1, and Table D-2 (if calculated) or attached method explanation and calculations (if determined from testing)	RT 530/17	scfh, wet
Calibration MPF (non-DP type monitors, only)	Table D-1 and attached calculations	Not reported	cal units [2]
Calibration Span Value	Table D-1 and attached calculations	RT 230/24, RT 530/36, RT 600/24	cal units
Flow Rate Span Value	Attached calculations	RT 530/90	scfh, wet
Full-Scale Range (Calibration)	Table D-1, column (8)	RT 530/49	cal units
Full-Scale Range (Reporting)	Attached calculations	RT 530/99	scfh, wet
Calibration Error Test Data	Not reported	RT 230/37, RT 230/50, RT 600/37, RT 600/50	cal units
Flow Rate	Not reported	RT 220/29 RT 220/39	scfh, wet

[1] See EDR v2.1 and instructions for additional flow reporting requirements (RATAs, Reference Method monitoring, etc.)

[2] sfpm, ksfpm, scfm, kscfm, scfh, kscfh, acfm, kacfm, acfh, kacfh, inH2O, mmscfh, mmacfh, afpm, kafpm

History: First published in June 1996, Update #9; revised in October 1999 Revised Manual

Quarterly Report Review Process for Determining Final Annual Emissions

Acid Rain Program
Quarterly Report Review Process for Determining Final Annual Data

The Acid Rain Program regulations (40 CFR Part 75) require affected sources to submit quarterly data reports for their affected units to the EPA no later than 30 days following the end of each calendar quarter. Each report must be signed and certified by the source's Designated Representative (DR) or Alternate Designated Representative (ADR) for accuracy and completeness. This document describes the Quarterly Report Review Process the EPA uses to evaluate quarterly reports and determine the accepted emissions value for each affected source. These final data are used for allowance reconciliation and compliance determination, and are made available to the public.

All quarterly reports submitted to the EPA are entered into the Emissions Tracking System (ETS) which performs automated data processing. ETS is maintained on the EPA mainframe computer located in Research Triangle Park, NC. The majority of reports are electronically submitted directly to ETS using "ETS-PC," an EPA-developed software program.

The EPA's Quarterly Report Review Process consists of the following steps:

1. **Data Review** -- All quarterly reports are analyzed to detect deficiencies and to identify reports that must be resubmitted to correct problems. The EPA also identifies reports that were not submitted by the appropriate reporting deadline.

2. **Data Resubmission** -- Revised quarterly reports are obtained from sources by a specified deadline to correct deficiencies found during the Data Review process.

3. **Data Dissemination** -- All data are reviewed and preliminary and final emissions data reports are prepared for public release and compliance determination.

These three primary activities are described below in further detail:

1. Data Review

The EPA's Data Review consists of four steps: Diskette Submission Review, Automated Quarterly Report Rejection Criteria Review, Automated Quarterly Report Critical Error Review, and Additional Quarterly Report Audits. These steps are described below:

A) <u>Diskette Submission Review</u> - The number of quarterly reports submitted on diskettes represents a small percentage of the total number of quarterly reports submitted to the EPA. Reports submitted on diskette must be accompanied by a letter containing certification statements signed by the DR or ADR. Diskette reports are examined and must pass the following rejection criteria (specific to diskette submissions) before they can be transmitted to the EPA mainframe for further automated analysis:

1) All reports contained on a diskette must be resubmitted if the diskette is found to contain a computer virus.
2) All reports contained on a diskette must be resubmitted if the diskette is unreadable (e.g., physically damaged).
3) All reports contained on a diskette in a compressed (*. ZIP) file or self-extracting (*.EXE) compressed file must be resubmitted if the EPA cannot successfully "decompress" the report.
4) Any report contained on a diskette must be resubmitted if the report is unreadable (e.g., wrong file format or corrupted) or missing.
5) Any report contained on a diskette must be resubmitted if the report contains two or more units that are not associated through their stack configuration.
6) Any report for a common or multiple stack configuration (including associated units), contained on a diskette must be resubmitted if the same unit or stack is contained in more than one report. The stack(s) and associated unit-level data must be contained in a single report.

The EPA will reject a diskette report if it fails any of these criteria and will notify the source by telephone that the report must be resubmitted by a stated deadline (typically within five calendar days after the telephone call). On the other hand, if a diskette report passes these criteria, the EPA will transmit it to the ETS for automated review.

B) Automated Quarterly Report Rejection Criteria Review - All reports submitted to ETS on the EPA mainframe are first tested against automated rejection criteria. These criteria determine whether a quarterly report is basically complete and internally consistent according to Part 75 reporting requirements, including the record types (RT) described in the Electronic Data Reporting Format (EDR), versions 1.3, 2.0, and 2.1. The EPA will reject a report if it fails any of the rejection criteria, and will inform the source that the report must be corrected and resubmitted (for tracking purposes, ETS assigns a Status Code of '6' to a rejected report).

Sources using ETS-PC to electronically submit reports to the EPA receive "instant feedback" containing the results from this automated review. After reviewing the feedback, the source may revise the report and resubmit it prior to the submission deadline. If a report is rejected (Status Code 6), the feedback states that the source must correct and resubmit the report to the EPA no later than 30 days from the date of the feedback (see Section 2. Data Resubmission). Sources using ETS-PC have the option of submitting a file numerous times before the submission deadline.

For a report submitted on diskette, the EPA provides the feedback in a letter to the DR approximately 20 days after the submission deadline. The letter will notify the DR of any rejected reports and will request that rejected reports be corrected and resubmitted no later than 30 days after the date of the letter (see Section 2. Data Resubmission). The DR may electronically resubmit the report using ETS-PC instead of resubmitting it on a diskette.

The following rejection criteria are applied during this automated review:

1) Does the report contain a facility identification record (RT100)?
2) Does the report contain only one facility identification record (RT100)?

3) Is the facility identification record (RT100) the first record in the report?
4) Is the plant code (ORISPL) in RT100 contained in the EPA's database of valid ORISPL codes?
5) Are the calendar year and/or quarter in RT100 correct?
6) Are all Unit IDs and/or Stack IDs in the report found in the EPA's database of valid IDs for the plant code (ORISPL)?
7) Does the report contain basic monitoring plan data (RT502 or RT503) for each unit and stack present in the report?
8) Is there a Unit Definition Record (RT502) for each unit ID contained in the report, and is there a Stack/Pipe Header Definition Record (RT503) for each Stack or Pipe ID contained in the report except for reports containing only nonoperational units or stacks?
9) Is there at least one of the following for each operating unit (defined in RT502) or stack/pipe (defined in RT503) in the report: emissions data (RT2xx or RT3xx), QA/QC test data and results (RT6xx), or operating data (RT300)?
10) Is there a summary emissions data record (RT301) for each unit, stack, or pipe reported in the report?
11) Does the Unit/Stack/Pipe ID specified in the ETS mainframe filename appear in the report?
12) Does the report contain only ASCII or EBCDIC-compliant characters (except for RTs 520, 550, 555, and 900/901/910)?
13) Do all records in the report begin with a valid record type code, as defined in EDR v1.3, v2.0, or v2.1?
14) Are SO_2 (RTs 310, 313, 314), CO_2 (RTs 330, 331) and NO_x (RTs 320, 323, 324) present in the file?
15) Does the sum of the hourly records for CO_2 (RT330) multiplied by the operating time (RT300) equal the total quarterly CO_2 tons reported in RT 301?
16) Does the quarterly average NO_x rate calculated from the hourly records for NO_x (RT 320 and 323) equal the reported quarterly average NO_x rate reported in RT301?
17) Are the Bias Adjustment Factors for SO_2 (RT200), Flow (RT220), and NO_x (RT320) greater than or equal to 1.00?
18) Is every hour of CO_2 mass emissions (RT 330) less than 9999 tons?
19) Is every hour of Heat Input Rate (RT 300) less than 99999 mmBtu/hour?
20) Do the concentration (2XX) and mass emission (3XX) record types contain positive emission values?

A report that passes the automated rejection criteria will next undergo an automated critical error review, described below.

C) _Automated Quarterly Report Critical Error Review_ - Each report that passes the automated rejection criteria then undergoes a second level of automated ETS software checks to detect critical errors. A report that fails any one of these checks is assigned a "Critical Error" status (Status Code 5) within ETS. In such a case the EPA will inform the source that the report contains critical errors that must be corrected in future submissions or the EPA may reject subsequent reports. In addition, if these errors that are of such a magnitude as to have a "significant" impact on the emissions (as defined in Section 2. Data Resubmission), the quarterly report containing the errors must be resubmitted.

Sources submitting their reports using ETS-PC will immediately receive the results from this automated critical error review in their feedback. After reviewing the feedback, the source may revise the report and resubmit it prior to the submission deadline. For a report submitted on a diskette, the source's DR will receive a feedback letter containing these results approximately 20 days after the report submission deadline. The DR may electronically resubmit the report using ETS-PC instead of resubmitting it on a diskette.

The following critical error criteria are applied during this automated review:

1) Does the sum of the hourly records for SO_2 (RTs 310, 313, and 314) multiplied by the operating time (RT300) equal the total quarterly SO_2 tons reported in RT 301?
2) Does the sum of the hourly records for Heat Input (RT300) multiplied by the operating time (RT300) equal the total quarterly Heat Input reported in RT301?
3) Are the appropriate hourly emissions (RT 302/313 and/or 303/314) present for an Appendix D unit?
4) Is the cumulative annual average NO_x emission rate reported in RT 301 less than 3.00 lb/mmBtu?
5) Are the cumulative annual SO_2 tons emitted reported in RT 301 less than 180,000 tons?
6) Is every hour of SO_2 mass emissions (RT 310, 313, and/or 314) less than 50,000 tons?
7) Is every hour of average NO_x emissions rate (RT 320, 323, and/or 324) less than 4.00 lb/mmBtu?
8) Is the EPA Accepted Value greater than or equal to the Cumulative Annual Value for SO_2, CO_2, NO_x, and Heat Input?
9) Is the sum of the hourly NO_x Mass emissions reported in RT 360 less than or equal to 50 tons?
10) Is the sum of the hourly SO_2 emissions reported in RT 360 less than or equal to 25 tons?
11) Do all data reported in the file fall within the submission quarter?
12) Are the proper program indicators being reported for each unit in RT 505?
13) Do the program indicators reported for each unit in RT 505 match those stored by the EPA?
14) Does the reporting frequency reported for each unit in RT 505 match what is stored by the EPA?
15) Is the fuel type reported in RT 585 appropriate for a Low Mass Emissions (LME) Unit ?
16) Is there a RT 585 for each pollutant (SO2, CO_2, and NO_x Rate)and heat input present in the file?

After a report completes the critical error review, it then undergoes a final level of ETS software checks to detect other types of errors and inconsistencies (“informational errors”). Results from this final analysis are also included in the ETS feedback provided to the DR. ETS generates messages to describe the informational errors (if any) detected in the report. The DR may then revise the report to correct informational errors and resubmit it to the EPA prior to the submission deadline. The DR must also ensure that such errors are corrected so they do not occur in subsequent quarterly reports.

As part of ongoing Quality Assurance (QA) activities, the EPA expects to incorporate certain informational errors into the set of critical error criteria (Status Code 5) or incorporate some informational errors or critical error criteria into the set of rejection criteria (Status Code 6). In other words, errors which are currently identified by ETS for the source to correct in future submissions may become errors which the source must correct before the quarterly report containing the specified error(s) can be accepted by the EPA.

D) <u>Additional Quarterly Report Audits</u> - In addition to the automated data review and feedback described above, the EPA may subject quarterly reports to an electronic audit as a part of ongoing QA activities where additional rejection criteria are applied. If a report fails any of these additional criteria, the EPA may notify the DR and require resubmission of that report, and/or initiate a field audit. Note that resubmission will be required if the audit results indicate that there is a “significant” impact on the reported emissions (as defined in Section 2. Data Resubmission).

Examples of criteria that the EPA may apply during a quarterly report audit are:

1) Are the reported emissions or heat input data consistent (for example, does the sum of the EPA-calculated hourly SO_2 emissions for the quarter multiplied by the operating time equal the quarterly total SO_2 emissions value reported in RT301)?
2) Are the hourly SO_2 mass emissions calculated correctly from the appropriate data elements?
3) Are the hourly NO_x emission rates calculated correctly from the appropriate data elements?
4) Are the hourly heat input rates calculated correctly from the appropriate data elements?
5) Is the correct bias adjustment factor applied for every hour, where appropriate?
6) Have the required quarterly linearity tests been conducted, passed, and reported within the required amount of time?
7) Have the required RATA tests been conducted, passed, and reported within the required amount of time?
8) Have the required daily monitor calibration tests and flow monitor interference check tests been conducted and reported?
9) Has the required quarterly flow monitor leak check test been conducted and reported?
10) Are all monitors used to report emissions data certified?
11) If the quarterly report indicates that a recertification event occurred, were the test results submitted to the EPA?

Finally, the EPA may conduct periodic, independent field audits to assure compliance with Part 75 Continuous Emission Monitoring requirements. These field audits may include activities such as review of on-site records, CEMS inspections, and QA test observations. The EPA expects that when errors or deficiencies are discovered through the field audit program, appropriate corrective action will be taken independently of the quarterly review process described here.

After reviewing the results from these additional audits, the EPA may expand the automated rejection criteria (Status Code 6) or critical error criteria (Status Code 5) applied by the ETS software to include one or more new criteria and implement them in a subsequent calendar quarter.

2. Data Resubmission

As described above in the Data Review section, a source may need to resubmit a quarterly report to correct specified problems. A quarterly report resubmitted to the EPA replaces the previous submission in ETS and at a minimum will also undergo the automated Data Review processes described above. As a result, each resubmitted report must be complete; it must contain all the required data records for emissions, QA/QC, and monitoring plan data. Additionally, a resubmitted report must be accompanied by the Designated Representative Signature and Certification Statements, included in RTs 900/901 or in a hard-copy letter. If the resubmitted report passes all rejection criteria and critical error criteria and the problem(s) identified in the prior submission was also corrected, no further action is required by the DR.

<u>Resubmission Procedures and Deadlines</u>

During the 30-day quarterly report submission period following the end of each calendar quarter, a source that uses ETS-PC to submit its reports may revise and resubmit the reports for that quarter, as necessary, before the quarterly report deadline. As a result, most of the quarterly reports will pass all rejection and critical error criteria before the submission deadline. The remaining reports typically contain problems that caused the EPA to reject them, or they contain other significant inaccuracies identified by the EPA and/or source. These reports will need to be corrected and resubmitted to the EPA. Resubmission deadlines, including final quarterly report resubmission deadlines, are discussed below.

After the quarterly reporting deadline, a source must first contact the EPA before resubmitting a quarterly report so the EPA can determine whether the resubmission is permissible and prepare ETS to receive the resubmission. If the EPA has rejected the report, the source DR must correct the report and resubmit it by the deadline specified in the feedback, or resubmit it according to supplemental EPA guidance (for example, if the report was rejected during an audit). If a report contains critical errors or contains other significant errors identified by the EPA and/or source (as described below), the report must be resubmitted according to EPA guidance.

If the EPA and/or the source discover an error which impacts the emissions results, the EPA will determine whether the impact is significant and warrants correction of the emissions data through the resubmission of any or all of the quarterly reports for that calendar year. If a source discovers such an error, the source may voluntarily inform the EPA and request that the EPA allow resubmission of the affected report(s). If the EPA approves the request, the source will be instructed to resubmit the quarterly report. As part of this process, the EPA will first consider whether the emissions data will be used for compliance determinations. For example, in the case of a unit where the SO_2 emissions data are used to calculate allowance deductions for compliance with the Acid Rain Program emission limitation requirements, the EPA will require the source to correct the data if the error in the reported SO_2 value was greater than or equal to one ton. The following criteria are used to determine whether a quarterly report should be resubmitted to the EPA:

1) Are the reported SO_2 mass emissions correct within 1.0 ton or less?
2) Is the reported NO_x emission rate correct within 0.01 lb/mmBtu or less?
3) Is the reported heat input correct within 1000 mmBtu or less?
4) Are the reported CO_2 mass emissions correct within10.0 tons or less?
5) Are required quarterly linearity test data and results (RT601 and 602) reported and are they complete?
6) Are required RATA test data and results (RT610 and 611) reported and are they complete?
7) Are the required daily monitor calibration tests and flow monitor interference check tests reported and are they complete?
8) Was the required quarterly flow monitor leak check test reported and was it complete?
9) If a report was submitted via direct electronic submission and the Electronic DR Signature and Certification Statements (RT900 and 901) were submitted instead of a hard copy letter containing the DR certification and signature, are these record types correct, complete, and present?
10) Are the reported emissions or heat input data consistent (for example, the sum of the reported hourly SO_2 emissions for the quarter multiplied by the operating time does equal the quarterly total SO_2 emissions value reported in RT301)?
11) Is the quarterly report free of errors that EPA may determine will have a significant impact on the data quality?

As part of ongoing QA activities, the EPA may modify this criteria.

<u>Final Quarterly Report Resubmission Deadlines:</u>

To finalize the year-to-date emissions data as early as possible in anticipation of annual allowance reconciliation and compliance determination, the EPA has established the following final quarterly report resubmission deadlines for specified calendar quarters:

1st quarter 2000 - Resubmission Deadline: 07/31/2000

2nd quarter 2000 - Resubmission Deadline: 10/31/2000

3rd quarter 2000 - Resubmission Deadline: 12/29/2000

4th quarter 2000 - Resubmission Deadline: 03/30/2001

While the EPA will make every effort to assure that the current year's data are accurate, the EPA will not unilaterally change or correct submitted data without providing notice to the affected source. To the extent practicable, data reconciliation efforts, including resubmissions, will be made in cooperation with the source. Nonetheless, the responsibility to ensure the accuracy of the data submissions remains with the source.

3. Data Dissemination

All quarterly reports received by the EPA are maintained in a central database within ETS. This database is updated when quarterly reports are resubmitted. The EPA regularly extracts data from ETS for public distribution and for annual allowance reconciliation and compliance purposes. Reports containing the preliminary quarterly and year-to-date summary emissions and related data are released to the public on a quarterly basis, approximately 30 days after the end of each calender quarter. Final annual summary emissions data are available approximately nine months after the end of the calendar year.

The summary reports and related data (including individual quarterly reports) can be obtained from the EPA's Acid Rain Program home page on the World Wide Web (http://www.epa.gov/acidrain/edata.html#agg).