

additional in-line fuel flowmeter is required to account for the unburned fuel. Record the flow of each fuel combusted by the unit as the difference between the flow measured in the pipe leading to the unit and the flow in the pipe diverting fuel away from the unit.

2.1.2 Install and use fuel flowmeters meeting the requirements of this appendix in a pipe going to each unit, or install and use a fuel flowmeter in a common pipe header (i.e., a pipe carrying fuel for multiple units). If the flowmeter is installed in a common pipe header, do one of the following:

2.1.2.1 Measure the fuel flow in the common pipe and combine SO₂ mass emissions for the affected units for recordkeeping and compliance purposes; or

2.1.2.2 Provide information satisfactory to the Administrator on methods for apportioning SO₂ mass emissions and heat input to each of the affected units demonstrating that the method ensures complete and accurate accounting of all emissions regulated under this part. The information shall be provided to the Administrator through a petition submitted by the designated representative under §75.66. Satisfactory information includes apportionment using fuel flow measurements, the ratio of load (in MWe) in each unit to the total load for all units receiving fuel from the common pipe header, or the ratio of steam flow (in 1000 lb/hr) at each unit to the total steam flow for all units receiving fuel from the common pipe header.

2.1.3 For a gas-fired unit or an oil-fired unit that continuously or frequently combusts a supplemental fuel for flame stabilization or safety purposes, measure the flow of the supplemental fuel with a fuel flowmeter meeting the requirements of this appendix.

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

2.1.5 Each fuel flowmeter used to meet the requirements of this protocol shall meet a flowmeter accuracy of ± 2.0 percent of the upper range value (i.e., maximum calibrated fuel flow rate), either by design or as calibrated and as measured under laboratory conditions by the manufacturer, by an independent laboratory, or by the owner or operator. The flowmeter accuracy must include all error from all parts of the fuel flowmeter

being calibrated based upon the contribution to the error in the flowrate.

2.1.5.1 Use the procedures in the following standards for flowmeter calibration or flowmeter design, as appropriate to the type of flowmeter: ASME MFC-3M-1989 with September 1990 Errata ("Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi"), ASME MFC-4M-1986 (Reaffirmed 1990), "Measurement of Gas Flow by Turbine Meters," American Gas Association Report No. 3, "Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids Part 1: General Equations and Uncertainty Guidelines" (October 1990 Edition), Part 2: "Specification and Installation Requirements" (February 1991 Edition) and Part 3: "Natural Gas Applications" (August 1992 edition), (excluding the modified flow-calculation method in Part 3) ASME MFC-5M-1985 ("Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters"), ASME MFC-6M-1987 with June 1987 Errata ("Measurement of Fluid Flow in Pipes Using Vortex Flow Meters"), ASME MFC-7M-1987 (Reaffirmed 1992), "Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles," ISO 8316: 1987(E) "Measurement of Liquid Flow in Closed Conduits—Method by Collection of the Liquid in a Volumetric Tank," or MFC-9M-1988 with December 1989 Errata ("Measurement of Liquid Flow in Closed Conduits by Weighing Method") for all other flow meter types (incorporated by reference under §75.6 of this part). The Administrator may also approve other procedures that use equipment traceable to National Institute of Standards and Technology (NIST) standards. Document other procedures, the equipment used, and the accuracy of the procedures in the monitoring plan for the unit and a petition submitted by the designated representative under §75.66(c). If the flowmeter accuracy exceeds ± 2.0 percent of the upper range value, the flowmeter does not qualify for use under this part.

2.1.5.2 Alternatively, a fuel flowmeter used for the purposes of this part may be calibrated or recalibrated at least annually (or, for fuel flowmeters measuring emergency fuel, backup fuel or fuel usage of peaking units, every four calendar quarters when the unit combusts the fuel measured by the fuel flowmeter) by comparing the measured flow of a flowmeter to the measured flow from another flowmeter which has been calibrated or recalibrated during the previous 365 days using a standard listed in section 2.1.5 of this appendix or other procedure approved by the Administrator under §75.66. Any secondary elements, such as pressure and temperature transmitters, must be calibrated immediately prior to the comparison. Perform the comparison over a period of no more than seven consecutive unit operating days. Compare the average of three fuel flow

readings for each meter at each of three different flow levels, corresponding to (1) normal full operating load, (2) normal minimum operating load, and (3) a load point approximately equally spaced between the full and minimum operating loads. Calculate the flowmeter accuracy at each of the three flow levels using the following equation:

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

Where:

ACC=Flow meter accuracy as a percentage of the upper range value, including all error from all parts of both flowmeters.

R=Average of the three flow measurements of the reference flow meter.

A=Average of the three measurements of the flow meter being tested.

URV=Upper range value of fuel flow meter being tested (i.e. maximum measurable flow).

If the flow meter accuracy exceeds ± 2.0 percent of the upper range value at any of the three flow levels, either recalibrate the flow meter until the accuracy is within the performance specification, or replace the flow meter with another one that is within the performance specification. Notwithstanding the requirement for annual calibration of the reference flowmeter, if a reference flowmeter and the flowmeter being tested are within ± 1.0 percent of the flowrate of each other during all in-place calibrations in a calendar year, then the reference flowmeter does not need to be calibrated before the next in-place calibration. This exception to calibration requirements for the reference flowmeter may be extended for periods up to five calendar years.

2.1.6 Quality Assurance

2.1.6.1 Recalibrate each fuel flowmeter to a flowmeter accuracy of ± 2.0 percent of the upper range value prior to use under this part at least annually (or, for fuel flowmeters measuring emergency fuel, backup fuel or fuel usage of peaking units, every four calendar quarters when the unit combusts the fuel measured by the fuel flowmeter), or more frequently if required by manufacturer specifications. Perform the recalibration using the procedures in section 2.1.5 of this appendix. For orifice-, nozzle-, and venturi-type flowmeters, also recalibrate the flowmeter the following calendar quarter using the procedures in section 2.1.6.2 of this appendix, whenever the fuel flowmeter accuracy during a calibration or test is greater than ± 1.0 percent of the upper range value, or whenever a visual inspection of the orifice, nozzle, or venturi identifies corrosion since the previous visual inspection.

2.1.6.2 For orifice-, nozzle-, and venturi-type flowmeters that are designed according to the standards in section 2.1.5 of this appendix, satisfy the calibration requirements of this appendix by calibrating the differential pressure transmitter or transducer, static pressure transmitter or transducer, and temperature transmitter or transducer, as applicable, using equipment that has a current certificate of traceability to NIST standards. In addition, conduct a visual inspection of the orifice, nozzle, or venturi at least annually.

2.2 Oil Sampling and Analysis

Perform sampling and analysis of as-fired oil to determine the percentage of sulfur by weight in the oil.

2.2.1 When combusting diesel fuel, sample the diesel fuel either (1) every day the unit combusts diesel fuel, or (2) upon receipt of a shipment of diesel fuel.

2.2.1.1 If the diesel fuel is sampled every day, use either the flow proportional method described in section 2.2.3 of this appendix or the daily manual method described in section 2.2.4 of this appendix.

2.2.1.2 If the diesel fuel is sampled upon delivery, calculate SO_2 emissions using the highest sulfur content of any oil supply combusted in the previous 30 days that the unit combusted oil. Diesel fuel sampling and analysis may be performed either by the owner or operator of an affected unit, an outside laboratory, or a fuel supplier, provided that sampling is performed according to ASTM D4057-88, "Standard Practice for Manual Sampling of Petroleum and Petroleum Products" (incorporated by reference under § 75.6 of this part).

2.2.2 Perform oil sampling every day the unit is combusting oil except as provided for diesel fuel. Use either the flow proportional method described in section 2.2.3 of this appendix or the daily manual method described in section 2.2.4 of this appendix.

2.2.3 Conduct flow proportional oil sampling or continuous drip oil sampling in accordance with ASTM D4177-82 (Reapproved 1990), "Standard Practice for Automatic Sampling of Petroleum and Petroleum Products" (incorporated by reference under § 75.6), every day the unit is combusting oil. Extract oil at least once every hour and blend into a daily composite sample. The sample composite period may not exceed 24 hr.

2.2.4 Representative as-fired oil samples may be taken manually every day that the unit combusts oil according to ASTM D4057-88, "Standard Practice for Manual Sampling of Petroleum and Petroleum Products" (incorporated by reference under § 75.6), provided that the highest fuel sulfur content recorded at that unit from the most recent 30 daily samples is used for the purposes of calculating SO_2 emissions under section 3 of

this appendix. Use the gross calorific value measured from that day's sample to calculate heat input. If oil supplies with different sulfur contents are combusted on the same day, sample the highest sulfur fuel combusted that day.

NOTE: For units with pressurized fuel flow lines such as some diesel and dual-fuel reciprocating internal combustion engine units, a manual sample may be taken from the point closest to the unit where it is safe to take a sample (including back to the oil tank), rather than just prior to entry to the boiler or combustion chamber. As-delivered manual samples of diesel fuel need not be as-fired.

2.2.5 Split and label each oil sample. Maintain a portion (at least 200 cc) of each sample throughout the calendar year and in all cases for not less than 90 calendar days after the end of the calendar year allowance accounting period. Analyze oil samples for percent sulfur content by weight in accordance with ASTM D129-91, "Standard Test Method for Sulfur in Petroleum Products (General Bomb Method)," ASTM D1552-90, "Standard Test Method for Sulfur in Petroleum Products (High Temperature Method)," ASTM D2622-92, "Standard Test Method for Sulfur in Petroleum Products by X-Ray Spectrometry," or ASTM D4294-90, "Standard Test Method for Sulfur in Petroleum Products by Energy-Dispersive X-Ray Fluorescence Spectroscopy" (incorporated by reference under §75.6).

2.2.6 Where the flowmeter records volumetric flow rather than mass flow, analyze oil samples to determine the density or specific gravity of the oil. Determine the density or specific gravity of the oil sample in accordance with ASTM D287-82 (Reapproved 1991), "Standard Test Method for API Gravity of Crude Petroleum and Petroleum Products (Hydrometer Method)," ASTM D941-88, "Standard Test Method for Density and Relative Density (Specific Gravity) of Liquids by Lipkin Bicapillary Pycnometer," ASTM D1217-91, "Standard Test Method for Density and Relative Density (Specific Gravity) of Liquids by Bingham Pycnometer," ASTM D1481-91, "Standard Test Method for Density and Relative Density (Specific Gravity) of Viscous Materials by Lipkin Bicapillary," ASTM D1480-91, "Standard Test Method for Density and Relative Density (Specific Gravity) of Viscous Materials by Bingham Pycnometer," ASTM D1298-85 (Reapproved 1990), "Standard Practice for Density, Relative Density (Specific Gravity) or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method," or ASTM D4052-91, "Standard Test Method for Density and Relative Density of Liquids by Digital Density Meter" (incorporated by reference under §75.6).

2.2.7 Analyze oil samples to determine the heat content of the fuel. Determine oil heat

content in accordance with ASTM D240-87 (Reapproved 1991), "Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter," ASTM D2382-88, "Standard Test Method for Heat or Combustion of Hydrocarbon Fuels by Bomb Calorimeter (High-Precision Method)," or ASTM D2015-91, "Standard Test Method for Gross Calorific Value of Coal and Coke by the Adiabatic Bomb Calorimeter" (incorporated by reference under §75.6) or any other procedures listed in section 5.5 of appendix F of this part.

2.2.8 Results from the oil sample analysis must be available no later than thirty calendar days after the sample is composited or taken. However, during an audit, the Administrator may require that the results of the analysis be available within 5 business days, or sooner if practicable.

2.3 SO₂ Emissions from Combustion of Gaseous Fuels

Account for the hourly SO₂ mass emissions due to combustion of gaseous fuels for each day when gaseous fuels are combusted by the unit using the procedures in either section 2.3.1 or 2.3.2.

2.3.1 Sample the gaseous fuel daily.

2.3.1.1 Analyze the sulfur content of the gaseous fuel in grain/100 scf using ASTM D1072-90, "Standard Test Method for Total Sulfur in Fuel Gases", ASTM D4468-85 (Reapproved 1989) "Standard Test Method for Total Sulfur in Gaseous Fuels by Hydrogenolysis and Rateometric Colorimetry," ASTM D5504-94 "Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence," or ASTM D3246-81 (Reapproved 1987) "Standard Test Method for Sulfur in Petroleum Gas by Oxidative Microcoulometry" (incorporated by reference under §75.6). The test may be performed by the owner or operator, an outside laboratory, or the gas supplier.

2.3.1.2 Results from the analysis must be available on-site no later than thirty calendar days after the sample is taken.

2.3.1.3 Determine the heat content or gross calorific value for at least one sample each month and use the procedures of section 5.5 of appendix F of this part to determine the heat input for each hour the unit combusted gaseous fuel.

2.3.1.4 Multiply the sulfur content by the hourly metered volume of gas combusted in 100 scf, using Equation D-4 of this appendix.

2.3.2 If the fuel is pipeline natural gas, calculate SO₂ emissions using a default SO₂ emission rate of 0.0006 lb/mmBtu.

2.3.2.1 Use the default SO₂ emission rate of 0.0006 lb/mmBtu and the hourly heat input from pipeline natural gas in mmBtu/hr, as determined using the procedures in section 5.5 of appendix F of this part. Calculate SO₂

emissions using Equation D-5 of this appendix.

2.3.2.2 Provide information on the contractual sulfur content from the pipeline gas supplier in the monitoring plan for the unit, demonstrating that the gas has a hydrogen sulfide content of 1 grain/100 scf or less, and a total sulfur content of 20 grain/100 scf or less.

2.4 Missing Data Procedures.

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

2.4.1 When sulfur content or oil density data from the analysis of an oil sample or when sulfur content data from the analysis of a gaseous fuel sample are missing or invalid, substitute, as applicable, the highest measured sulfur content or oil density (if using a volumetric oil flowmeter) recorded during the previous 30 days when the unit burned that fuel. If no previous sulfur content data are available, substitute the maximum potential sulfur content of that fuel.

2.4.2 When gross calorific value data from the analysis of an oil sample are missing or invalid, substitute the highest measured gross calorific value recorded during the previous 30 days that the unit burned oil. When gross calorific value data from the analysis of a monthly gaseous fuel sample are missing or invalid, substitute the highest measured gross calorific value recorded during the previous three months that the unit burned gaseous fuel.

2.4.3 Whenever data are missing from any fuel flowmeter that is part of an excepted monitoring system under appendix D or E of this part, where the fuel flowmeter data are required to determine the amount of fuel combusted by the unit, use the procedures in either section 2.4.3.1 or sections 2.4.3.2 and 2.4.3.3 prior to January 1, 1996 and use the procedures in sections 2.4.3.2 and 2.4.3.3 but do not use the procedures in section 2.4.3.1 on or after January 1, 1996 to account for the flow rate of fuel combusted at the unit for each hour during the missing data period.

2.4.3.1 [Reserved]

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

range or a higher load range during any hour of the missing data period for that fuel, substitute the maximum potential fuel flow rate. The maximum potential fuel flow rate is the lesser of the following: (1) the maximum fuel flow rate the unit is capable of combusting or (2) the maximum flow rate that the flowmeter can measure.

2.4.3.3 For hours where two or more fuels are combusted, substitute the maximum hourly fuel flow rate measured and recorded by the flowmeter (or flowmeters, where fuel is recirculated) for the fuel for which data are missing at the corresponding load range recorded for each missing hour during the previous 720 hours when the unit combusted that fuel with any other fuel. For hours where no previous recorded fuel flow rate data are available for that fuel during the missing data period, calculate and substitute the maximum potential flow rate of that fuel for the unit as defined in section 2.4.3.2 of this appendix.

2.4.4. In any case where the missing data provisions of this section require substitution of data measured and recorded more than three years (26,280 clock hours) prior to the date and time of the missing data period, use three years (26,280 clock hours) in place of the prescribed lookback period.

3. CALCULATIONS

Use the calculation procedures in section 3.1 of this appendix to calculate SO₂ mass emissions. Where an oil flowmeter records volumetric flow, use the calculation procedures in section 3.2 of this appendix to calculate mass flow of oil. Calculate hourly SO₂ mass emissions from gaseous fuel using the procedures in section 3.3 of this appendix. Calculate hourly heat input for oil and for gaseous fuel using the equations in section 5.5 of Appendix F of this part. Calculate total SO₂ mass emissions and heat input as provided under section 3.4 of this appendix.

3.1 SO₂ Mass Emissions Calculation for Oil

3.1.1 Use the following equation to calculate SO₂ mass emissions per hour (in lb/hr).

$$M_{SO_2} = 2.0 \times M_{oil} \times \%S_{oil} / 100.0$$

(Eq. D-2)

Where:

M_{SO_2} = Hourly mass of SO₂ emitted from combustion of oil, lb/hr.

M_{oil} = Mass of oil consumed per hr, lb/hr.

$\%S_{oil}$ = Percentage of sulfur by weight measured in the sample.

2.0 = Ratio of lb SO₂/lb S.

3.1.2 Record the SO₂ mass emissions from oil for each hour that oil is combusted.

3.2 Mass Flow Calculation for Oil Using Volumetric Flow

3.2.1 Where the oil flowmeter records volumetric flow rather than mass flow, calculate and record the oil mass flow for each hourly period using hourly oil flow measurements and the density or specific gravity of the oil sample.

3.2.2 Convert density, specific gravity, or API gravity of the oil sample to density of the oil sample at the sampling location's temperature using ASTM D1250-80 (Reapproved 1990), "Standard Guide for Petroleum Measurement Tables" (incorporated by reference under §75.6 of this part).

3.2.3 Where density of the oil is determined by the applicable ASTM procedures from section 2.2.5 of this appendix, use the following equation to calculate the mass of oil consumed (in lb/hr).

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

where,

M_{oil} = Mass of oil consumed per hr, lb/hr.

V_{oil} = Volume of oil consumed per hr, measured in scf, gal, barrels, or m³.

D_{oil} = Density of oil, measured in lb/scf, lb/gal, lb/barrel, or lb/m³.

3.2.4 Calculate the hourly heat input to the unit from oil (mmBtu) by multiplying the heat content of the daily oil sample by the hourly oil mass.

3.3 SO₂ Mass Emissions Calculation for Gaseous Fuels

3.3.1 Use the following equation to calculate the SO₂ emissions using the gas sampling and analysis procedures in section 2.3.1 of this appendix:

$$M_{SO_2g} = \left(\frac{2.0}{7000} \right) \times Q_g \times S_g \quad (\text{Eq. D-4})$$

Where:

M_{SO_2g} = Hourly mass of SO₂ emitted due to combustion of gaseous fuel, lb/hr.

Q_g = Hourly metered flow or amount of gaseous fuel combusted, 100 scf/hr.

S_g = Sulfur content of gaseous fuel, in grain/100 scf.

2.0 = Ratio of lb SO₂/lb S.

7000 = Conversion of grains/100 scf to lb/100 scf.

3.3.2 Use the following equation to calculate the SO₂ emissions using the 0.0006 lb/mmBtu emission rate in section 2.3.2 of this appendix:

$$M_{SO_2g} = ER \times HI_g \quad (\text{Eq. D-5})$$

Where:

M_{SO_2g} = Hourly mass of SO₂ emissions from combustion of pipeline natural gas, lb/hr.

ER = SO₂ emission rate of 0.0006 lb/mmBtu for pipeline natural gas.

HI_g = Hourly heat input of pipeline natural gas, calculated using procedures in appendix F of this part, in mmBtu/hr.

3.3.3 Record the SO₂ mass emissions for each hour when the unit combusts gaseous fuel.

3.4 Records and Reports

Calculate and record quarterly and cumulative SO₂ mass emissions and heat input for each calendar quarter and for the calendar year by summing the hourly values. Calculate and record SO₂ emissions and heat input data using a data acquisition and handling system. Report these data in a standard electronic format specified by the Administrator.

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APPENDIX E TO PART 75—OPTIONAL NO_x EMISSIONS ESTIMATION PROTOCOL FOR GAS-FIRED PEAKING UNITS AND OIL-FIRED PEAKING UNITS

1. APPLICABILITY

1.1 Unit Operation Requirements

This NO_x emissions estimation procedure may be used in lieu of a continuous NO_x emission monitoring system (lb/mmBtu) for determining the average NO_x emission rate and hourly NO_x rate from gas-fired peaking units and oil-fired peaking units as defined in §72.2 of this chapter. If a unit's operations exceed the levels required to be a peaking unit, install and certify a continuous NO_x emission monitoring system no later than December 31 of the following calendar year. The provisions of §75.12 apply to excepted monitoring systems under this appendix.

1.2 Certification

1.2.1 Pursuant to the procedures in §75.20, complete all testing requirements to certify use of this protocol in lieu of a NO_x continuous emission monitoring system no later than the applicable deadline specified in §75.4. Apply to the Administrator for certification to use this method no later than 45 days after the completion of all certification testing. Whenever the monitoring method is to be changed, reapply to the Administrator for certification of the new monitoring method.

1.2.2 If the owner or operator has already successfully completed certification testing of the unit using the protocol of appendix E of part 75 and submitted a certification application under §75.20(g) prior to _____ July 17, 1995, the unit's monitoring system does not need to repeat initial certification testing using the revised procedures published _____ May 17, 1995.

2. PROCEDURE

2.1 Initial Performance Testing

Use the following procedures for: measuring NO_x emission rates at heat input rate levels corresponding to different load levels; measuring heat input rate; and plotting the correlation between heat input rate and NO_x emission rate, in order to determine the emission rate of the unit(s).

2.1.1 Load Selection

Establish at least four approximately equally spaced operating load points, ranging from the maximum operating load to the minimum operating load. Select the maximum and minimum operating load from the operating history of the unit during the most recent two years. (If projections indicate that the unit's maximum or minimum operating load during the next five years will be significantly different from the most recent two years, select the maximum and minimum operating load based on the projected dispatched load of the unit.) For new gas-fired peaking units or new oil-fired peaking units, select the maximum and minimum operating load from the expected maximum and minimum load to be dispatched to the unit in the first five calendar years of operation.

2.1.2 NO_x and O₂ Concentration Measurements

Use the following procedures to measure NO_x and O₂ concentration in order to determine NO_x emission rate.

2.1.2.1 For boilers, select an excess O₂ level for each fuel (and, optionally, for each combination of fuels) to be combusted that is representative for each of the four or more load levels. If a boiler operates using a single, consistent combination of fuels only, the testing may be performed using the combination rather than each fuel. If a fuel is combusted only for the purpose of testing ignition of the burners for a period of five minutes or less per ignition test or for start-up, then the boiler NO_x emission rate does not need to be tested separately for that fuel. Operate the boiler at a normal or conservatively high excess oxygen level in conjunction with these tests. Measure the NO_x and O₂ at each load point for each fuel or consistent fuel combination (and, optionally, for each combination of fuels) to be combusted. Measure the NO_x and O₂ concentrations according to Method 7E and 3A in appendix A of part 60 of this chapter. Select sampling points as specified in section 5.1, Method 3 in appendix A of part 60 of this chapter. The designated representative for the unit may also petition the Administrator under §75.66 to use fewer sampling points. Such a petition shall include the proposed alternative sampling procedure and information demonstrat-

ing that there is no concentration stratification at the sampling location.

2.1.2.2 For stationary gas turbines, select sampling points and measure the NO_x and O₂ concentrations at each load point for each fuel or consistent combination of fuels (and, optionally, each combination of fuels) according to appendix A, Method 20 of part 60 of this chapter. For diesel or dual fuel reciprocating engines, measure the NO_x and O₂ concentrations according to Method 20, but modify Method 20 by selecting a sampling site to be as close as practical to the exhaust of the engine.

2.1.2.3 Allow the unit to stabilize for a minimum of 15 minutes (or longer if needed for the NO_x and O₂ readings to stabilize) prior to commencing NO_x, O₂, and heat input measurements. Determine the average measurement system response time according to section 5.5 of Method 20 in appendix A, part 60 of this chapter. When inserting the probe into the flue gas for the first sampling point in each traverse, sample for at least one minute plus twice the average measurement system response time (or longer, if necessary to obtain a stable reading). For all other sampling points in each traverse, sample for at least one minute plus the average measurement response time (or longer, if necessary to obtain a stable reading). Perform three test runs at each load condition and obtain an arithmetic average of the runs for each load condition. During each test run on a boiler, record the boiler excess oxygen level at 5 minute intervals.

2.1.3 Heat Input

Measure the total heat input (mmBtu) and heat input rate during testing (mmBtu/hr) as follows:

2.1.3.1 When the unit is combusting fuel, measure and record the flow of fuel consumed. Measure the flow of fuel with an in-line flowmeter(s) and automatically record the data. If a portion of the flow is diverted from the unit without being burned, and that diversion occurs downstream of the fuel flowmeter, an in-line flowmeter is required to account for the unburned fuel. Install and calibrate in-line flow meters using the procedures and specifications contained in sections 2.1.2, 2.1.3, 2.1.4, and 2.1.5 of appendix D of this part. Correct any gaseous fuel flow rate measured at actual temperature and pressure to standard conditions of 68°F and 29.92 inches of mercury.

2.1.3.2 For liquid fuels, analyze fuel samples taken according to the requirements of section 2.2 of appendix D of this part to determine the heat content of the fuel. Determine heat content of liquid or gaseous fuel in accordance with the procedures in appendix F of this part. Calculate the heat input rate during testing (mmBtu/hr) associated with each load condition in accordance with Equations F-19 or F-20 in appendix F of this