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State of Nevada
Division of Environmental Protection
Bureau of Air Quality Planning

Greenhouse Gas Emissions

Mandatory Reporter Monitoring Guidelines

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Referenced Citations

Many of the citations that are referenced and relied upon in these MRMG are often revised. To ensure that the correct versions of these reference materials are utilized, they are identified below with their corresponding referenced dates of publication. As this document is revised and/or updated, these references will also be reviewed and updated as necessary.

Citation	Effective Date
§40 CFR Part 75 – Acid Rain	
Appendix A to §40 CFR Part 75—Specifications and Test Procedures	
Appendix B to §40 CFR Part 75—Quality Assurance and Quality Control Procedures	
Subpart D of §40 CFR Part 75—Missing Data Substitution Procedures	

Introduction

During the 2007 legislative session, the Nevada Legislature created Nevada Revised Statute (NRS) 445B.370. NRS 445B.370 directs the State Environmental Commission (SEC) to establish regulations that mandate the reporting of greenhouse gas (GHG) emissions to a registry, from affected units located throughout the state. NRS 445B.370 defines an affected unit as a unit for the generation of electricity that: (1) Has a maximum design output capacity of not less than 5 megawatts; (2) Emits a greenhouse gas; and (3) Generates electricity for sale. An affected unit is not a unit that uses renewable energy as defined in NRS 704.7811. Greenhouse gases are defined in NRS 445B.137 as any of the following gases, either alone or in combination:

(1) Carbon Dioxide (CO_2);
(2) Hydrofluorocarbons;
(3) Methane (CH_4);
(4) Nitrous Oxide (N_2O);
(5) Perfluorocarbons; and
(6) Sulfur Hexafluoride (SF_6).

All GHG emissions must be reported to the registry on an annual basis.

On (DATE) the SEC adopted Nevada Administrative Code (NAC) 445B.XXX through 445B.XXX that set forth the regulatory provisions required of NRS 445B.370. These provisions require GHGs emitted by affected units be determined in accordance with Monitoring Guidelines established by the Division. Monitoring Guidelines may be established by the Division as allowed for in NAC 445B.255. This document, "*The Mandatory Reporter Monitoring Guidelines*" (MRMG), as amended from time to time, shall serve as the referenced Monitoring Guidelines for the determination and reporting of greenhouse gas emissions.

Purpose of the Guidelines

These MRMG have been developed to establish a common set of GHG emissions quantification methodologies to ensure that reported emissions are consistent (i.e. 1-ton of CO_2 is equal to 1-ton of CO_2). These MRMG are based on a two-tier emissions quantification system that ranks quantification methodologies according to their levels of accuracy (high and low). To ensure consistency, the MRMG contain procedures for reducing measured emissions concentration data to mass emissions. Likewise, procedures are also established so that the use of emissions factors and related fuel characteristics and/or process information is consistently used to determine mass emissions. This will result in the most consistent reporting of GHGs.

Affected Unit GHG Emissions

While the definition of greenhouse gases includes six different gasses, only three of these gases, CO_2, CH_4, and N_2O, are emitted from the combustion of fossil fuels in affected units. Therefore, these guidelines focus specifically on the methodologies and procedures for determining emissions of these three gasses from affected units.

Emissions Quantification & Ranking

It is important to use the most accurate information and emissions determination methodologies available for the basis of reporting GHG emissions. Therefore, affected units that measure GHG emissions directly through a Continuous Emissions Monitoring System (CEMS) are required to utilize the measured data for GHG reporting purposes. Since this is the best methodology for determining these emissions it is given the highest tiered ranking (Level-1). For GHG emissions that are not directly measured, emissions must be determined through a variety of calculation methodologies which are less accurate than direct emissions measurement. These calculation-based methodologies have been given a lower tiered ranking (Level-2).

Regardless of the methodology utilized, it is important to report consistently over time to ensure the comparability of the GHG emissions data. However, if the use of the higher tier method for a particular unit becomes available, it is required that the more accurate emissions data be reported. It should also be noted that if an affected unit does not operate, or otherwise emit greenhouse gases during a particular calendar year, the reporter must still report emissions of zero for the reporting period.

Level - 1 Direct Measurement Methodology

As stated above, the quantification of emissions based on CEMS is a Level-1 methodology. Direct measurement based methodologies determine emissions by means of continuously measuring exhaust gas flow and the concentration of a substance in the flue gas. For purposes of determining GHG emissions, it is expected that CO_2 or O_2 are likely the only two flue gases that may be measured via CEMS. This is because these two gases are regularly measured directly for purposes of determining the amount of CO_2 emitted in order to comply with the federal Part 75 Acid Rain provisions. The measuring and reporting of GHG emissions based on the Acid Rain required CEMS are a valid measurement methodology.

Alternatively, if an affected unit is not subject to the Acid Rain provisions, yet otherwise directly measures CO_2 or O_2 via a CEMS, it is likely that the data obtained from these CEMS is also appropriate for GHG reporting purposes.

Chapter 1 of these guidelines consists of the required procedures for direct measurement of CO_2 or O_2 and flue gas flow. These procedures must be utilized by each affected unit that continuously measures these flue gas parameters by a CEMS.

Level - 2 Fuel Carbon Content Calculation Methodology (CO_2 Only)

When CO_2 or O_2 are not measured continuously, reporters will be required to use calculation based methodologies to quantify CO_2 emissions. For affected units that do not measure GHG emissions with a CEMS, emissions for all three pollutants must be determined based on a calculation methodology. CO_2 can be determined by two methods of calculation. The preferred method is to determine CO_2 emissions based upon the carbon content of the fuel(s) combusted. Chapter 2 contains the required procedures for fuel carbon content based calculation determinations. If carbon content data are not available, CO_2 emissions calculations must be based on default emissions factors as described in Level-3 below.

Level - 3 Fuel Use Calculation Methodology (CO_2, CH_4 & N_2O)

Reporters that do not have fuel carbon content data must utilize default emissions factors and annual fuel consumption for determining CO_2 emissions. Reporters that do not continuously monitor CH_4 or N_2O will also be required to use emissions factors and fuel consumption data to calculate CH_4 and N_2O emissions. Chapter 3 contains the required procedures for fuel use based emissions calculations for CO_2, CH_4 and N_2O.

(Optional) Level - 2.5 Performance Test Based Methodology

The MRMG have been developed with the ability to utilize sampling data from a current performance test of an affected unit to determine GHG emissions. This is an optional methodology that can be used to assist in developing unit specific emissions factors, determining emissions from combustion of fuels that may be utilized on an infrequent basis (backup or flame stabilization, etc.) or for periods when other calculation methods may not be appropriate for accurately determining GHG emissions.

Chapter 4 contains the required criteria and procedures for utilizing performance test based emissions data for GHG emissions determinations.

Reporting Emissions for Cogeneration & Combined Cycle Systems

For combined cycle system configurations, all GHG emissions produced by combustion in the combustion turbine, and any associated duct firing must be monitored and reported. For cogeneration system configurations, all GHG emissions produced by combustion in the affected unit utilized for electrical generation purposes will be considered as emissions associated with the affected unit. Heat utilized for non-electrical generating purposes will be subtracted out of the emissions total.

Document Structure

The balance of this document consists of 5 individual Chapters that set forth specific criteria for determining GHG emissions. Chapter 1 contains the requirements and procedures for Level-1 direct emissions monitoring for CO_2 (CEMS). Chapter 2 contains the requirements and procedures for Level-2 emissions estimations for CO_2 based on fuel carbon content data calculation methodologies. Chapter 3 covers Level-3 procedures for determining CO_2, CH_4 and N_2O emissions by use of default emissions factors. Chapter 4 contains requirements and procedures for utilizing performance test data as an alternative means of determining GHG emissions. This methodology is ranked as Level-2.5, because the quality of the emissions determined from this methodology falls between Level-2 and Level-3. Chapter 5 contains the requirements and procedures for combined heat and power units for ensuring correct emissions allocations for these units.

Chapter 1

Level-1

Direct CO_2 Emissions Monitoring

CO_2 or O_2 Continuous Emissions Monitoring Systems

Chapter 1 – CO_2 Continuous Emissions Monitoring

Background:

Most affected units utilize continuous emissions monitoring systems (CEMS) to track their CO_2 emissions. Owners or operators that report CO_2 emissions data to the U.S. EPA in accordance with §40 CFR Part 75 – Acid Rain must report the same CO_2 emissions information for the purposes of reporting to Nevada. CO_2 data must be monitored in accordance with the provisions of §40 CFR Part 75 – Acid Rain, which includes requirements for installing, certifying, operating, and maintaining CEMS for measuring and reporting CO_2 as well as SO_2, NO_2, O_2, opacity, and volumetric flow. The owner or operator of an affected unit may use either of the two following CEMS configurations to determine annual CO_2 emissions:

1. A monitor measuring CO_2 concentration percent by volume of flue gas and a flow monitoring system measuring the volumetric flow rate of flue gas can be used to determine CO_2 mass emissions. Annual CO_2 emissions are determined based on the operating time of the unit; or

2. A monitor measuring O_2 concentration percent by volume of flue gas and a flow monitoring system measuring the volumetric flow rate of flue gas combined with theoretical CO_2 and flue gas production by fuel characteristics can be used to determine CO_2 flue gas emissions and CO_2 mass emissions. Annual CO_2 emissions are determined based on the operating time of the unit.

Chapter 1 includes three Sections that provide for determining CO_2 emissions from affected units that are required to measure CO_2 emissions pursuant to the requirements of §40 CFR Part 75 – Acid Rain. If the owner or operator of an affected unit is **not** required to monitor CO_2 under §40 CFR Part 75 – Acid Rain but still conducts CO_2 CEMS monitoring, the procedures in this Chapter must be used to determine CO_2 emissions.

Section 1: CO_2 Continuous Emissions Monitoring General Requirements

The owner or operator of an affected unit that is required to comply with the monitoring provisions established in §40 CFR Part 75 – Acid Rain, and/or the reporting provisions established in NAC 445B.XXX, and that utilizes the CO_2 monitoring methods provided for in §40 CFR Part 75.10(a)(3)(i) or (iii) shall determine and report annual CO_2 emissions in accordance with the requirements established in Sections 1 through 3 of this Chapter. An owner or operator of an affected unit that is not required to comply with the monitoring provisions established in 40 CFR Part 75 – Acid Rain, but utilizes a CO_2 CEMS monitoring method shall determine and report annual CO_2 emissions in accordance with the requirements established in Sections 1 through 3 of this Chapter.

(a) *Primary Measurement Requirement.* The owner or operator shall measure CO_2 emissions for each affected unit by using method (1) or (2) and (3), below:

(1) The owner or operator shall install, certify, operate, and maintain, in accordance with all the requirements of this Section, a CO_2 continuous emission monitoring system and a flow monitoring system with an automated data acquisition and handling system for measuring and recording CO_2 concentration (in ppm or percent), volumetric gas flow (in scfh), and CO_2 mass emissions (in tons/hr) discharged to the atmosphere; or

(2) The owner or operator shall install, certify, operate, and maintain, in accordance with all the requirements of this Section, a flow monitoring system and a CO_2 continuous emission monitoring system that uses an O_2 concentration monitor to determine CO_2 emissions with an automated data acquisition and handling system for measuring and recording O_2 concentration (in percent), CO_2 concentration (in percent), volumetric gas flow (in scfh), and CO_2 mass emissions (in tons/hr) discharged to the atmosphere.

(3) A single certified flow monitoring system, a single certified diluent monitor, and/or a single automated data acquisition and handling system may be used to meet the requirements of this Chapter.

(b) *Primary Equipment Performance Requirements.* The owner or operator shall ensure that each continuous emission monitoring system required by this Section meets the equipment, installation, and performance specifications in Appendix A to §40 CFR Part 75—Specifications and Test Procedures; and is maintained according to the quality assurance and quality control procedures in Appendix B to §40 CFR Part 75—Quality Assurance and Quality Control Procedures; and shall record CO_2 emissions in the appropriate units of measurement (i.e., ppm, percent, tons/hr, tons/yr).

(c) *Primary Equipment Hourly Operating Requirements.* The owner or operator shall ensure that all continuous emission monitoring systems required by this Section are in operation and monitoring unit emissions at all times that the affected unit combusts any fuel and during periods of calibration, quality assurance, or preventive maintenance, performed pursuant to §40 CFR Part 75.21 and Appendix B to §40 CFR Part 75—Quality Assurance and Quality Control Procedures, periods of repair, periods of backups of data from the data acquisition and handling system, or recertification performed pursuant to §40 CFR Part 75.20. The owner or operator shall ensure that the following requirements are met:

(1) The owner or operator shall ensure that each continuous emission monitoring system is capable of completing a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-min interval. The owner or operator shall reduce all CO_2 concentrations, volumetric flow, O_2 concentration, CO_2 mass emissions data collected by the monitors to hourly averages. Hourly averages shall be computed using at least one data point in each fifteen minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly average may be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour) if data are unavailable as a result of the performance of calibration, quality assurance, or preventive maintenance activities pursuant to §40 CFR Part 75.21 and Appendix B to §40 CFR Part 75—Quality Assurance and Quality

Control Procedures, or backups of data from the data acquisition and handling system, or recertification, pursuant to §40 CFR Part 75.20. The owner or operator shall use all valid measurements or data points collected during an hour to calculate the hourly averages. All data points collected during an hour shall be, to the extent practicable, evenly spaced over the hour.

(2) Failure of a CO_2 or O_2 emissions concentration monitor, flow monitor, or moisture monitor to acquire the minimum number of data points for calculation of an hourly average in subsection (d)(1) of this Section shall result in the failure to obtain a valid hour of data and the loss of such component data for the entire hour. For a moisture monitoring system consisting of one or more oxygen analyzers capable of measuring O_2 on a wet-basis and a dry-basis, an hourly average percent moisture value is valid only if the minimum number of data points is acquired for both the wet-and dry-basis measurements. If a valid hour of data is not obtained, the owner or operator shall estimate and record emissions, moisture, or flow data for the missing hour by means of the automated data acquisition and handling system, in accordance with the applicable procedure for missing data substitution in §40 CFR Part 75 subpart D – Missing Data Substitution Procedures.

(d) *Optional Backup Monitor Requirements.* If the owner or operator chooses to use two or more continuous emission monitoring systems, each of which is capable of monitoring the same stack or duct at a specific affected unit, or group of units using a common stack, then the owner or operator shall designate one monitoring system as the primary monitoring system, and shall record this information in the monitoring plan, as provided for in §40 CFR Part 75.53. The owner or operator shall designate the other monitoring system(s) as backup monitoring system(s) in the monitoring plan. The backup monitoring system(s) shall be designated as redundant backup monitoring system(s), non-redundant backup monitoring system(s), or reference method backup system(s), as described in §40 CFR Part 75.20(d). When the certified primary monitoring system is operating and not out-of-control as defined in §40 CFR Part 75.24, only data from the certified primary monitoring system shall be reported as valid, quality-assured data. Thus, data from the backup monitoring system may be reported as valid, quality-assured data only when the backup is operating and not out-of-control as defined in §40 CFR Part 75.24 (or in the applicable reference method in Appendix A to 40 CFR Part 60-Test Methods) and when the certified primary monitoring system is not operating (or is operating but out-of-control). A particular monitor may be designated both as a certified primary monitor for one unit and as a certified redundant backup monitor for another unit.

(e) *Minimum Measurement Capability Requirement.* The owner or operator shall ensure that each continuous emission monitoring system is capable of accurately measuring, recording, and reporting data, and shall not incur an exceedance of the full scale range, except as provided in sections 2.1.1.5, 2.1.2.5, and 2.1.4.3 of Appendix A to §40 CFR Part 75—Specifications and Test Procedures.

(f) *Minimum Recording and Recordkeeping Requirements.* The owner or operator shall record and the responsible official shall report the hourly, daily, quarterly, and annual information collected under the requirements of this Section as specified in §40 CFR Part 75 Subpart F—Recordkeeping Requirements and Subpart G—Reporting Requirements.

Section 2: Specific Provisions for Monitoring CO_2 Emissions

CO_2 Continuous Emission Monitoring Method:

(a) CO_2 CEMS. An owner or operator that utilizes a CO_2 continuous emission monitoring system and flow monitoring system to comply with the requirements established in subsection (a)(1) of Section 1, of this Chapter, shall comply with the applicable provisions specified in subsections (b) through (g) of this Section.

(b) *Coal-Fired Units.* The owner or operator shall meet the requirements of subsection (a) of this Section for each affected coal-fired unit while the unit is combusting coal and/or any other fuel. The owner or operator shall utilize the applicable provisions of the procedures established in paragraph (a) of Section 3 of this Chapter.

(c) *Moisture Correction.* Where CO_2 concentration is measured on a dry basis, the owner or operator shall either:

(1) Report the appropriate fuel-specific default moisture value for each unit operating hour, selected from among the following: 3.0%, for anthracite coal; 6.0% for bituminous coal; 8.0% for sub-bituminous coal; 11.0% for lignite coal; 13.0% for wood and 14.0% for natural gas (boilers, only); or

(2) Install, operate, maintain, and quality assure a continuous moisture monitoring system for measuring and recording the moisture content of the flue gases, in order to correct the measured hourly volumetric flow rates for moisture when calculating CO_2 mass emissions (in lb/hr) using the procedures in Section 3 of this Chapter. The following continuous moisture monitoring systems are acceptable: a continuous moisture sensor; an oxygen analyzer (or analyzers) capable of measuring O_2 both on a wet basis and on a dry basis; or a stack temperature sensor and a moisture look-up table, i.e., a psychrometric chart (for saturated gas streams following wet scrubbers or other demonstrably saturated gas streams, only). The moisture monitoring system shall include as a component the automated data acquisition and handling system (DAHS) for recording and reporting both the raw data (e.g., hourly average wet-and dry-basis O_2 values) and the hourly average values of the stack gas moisture content derived from those data. When a moisture look-up table is used, the moisture monitoring system shall be represented as a single component, the certified DAHS, in the monitoring plan for the unit or common stack.

(d) *Unit with No Location for a Flow Monitor - Siting Requirements.* Where no location exists that satisfies the minimum physical siting criteria in Appendix A to §40 CFR Part 75 – Specifications and Test Procedures for installation of a flow monitor in either the stack or the ducts serving an affected unit or installation of a flow monitor in either the stack or ducts is demonstrated to the satisfaction of the Administrator to be technically infeasible, either:

(1) The designated representative shall petition the Director for an alternative method for monitoring volumetric flow; or

(2) The owner or operator shall construct a new stack or modify existing ductwork to accommodate the installation of a flow monitor; or

(3) The owner or operator shall install a flow monitor in any existing location in the stack or ducts serving the affected unit at which the monitor can achieve the performance specifications of this part.

(e) *Common Stack Procedures.* The following procedures shall be used when more than one unit uses a common stack:

(1) *Unit utilizing common stack.* When an affected unit utilizes a common stack with one or more other affected units the owner or operator shall:

(i) Install, certify, operate, and maintain a CO_2 continuous emission monitoring system and flow monitoring system in the duct to the common stack from each affected unit; or

(ii) Install, certify, operate, and maintain a CO_2 continuous emission monitoring system and flow monitoring system in the common stack and combine emissions for the affected units for recordkeeping and compliance purposes.

(A) Combine emissions for the affected units for recordkeeping and compliance purposes; or

(B) Provide information satisfactory to the Director on methods for apportioning CO_2 mass emissions measured in the common stack to each of the affected units. The Director may approve such substitute methods for apportioning CO_2 mass emissions measured in a common stack whenever the method ensures complete and accurate accounting of all emissions regulated under this part.

(f) *Unit with Bypass Stack.* Whenever any portion of the flue gases from an affected unit can be routed through a bypass stack so as to avoid the installed CO_2 continuous emission monitoring system and flow monitoring system, the owner or operator shall either:

(1) Install, certify, operate, and maintain separate CO_2 continuous emission monitoring systems and flow monitoring systems on the main stack and the bypass stack and calculate CO_2 mass emissions for the unit as the sum of the CO_2 mass emissions measured at the two stacks; or

(2) Monitor CO_2 mass emissions at the main stack using CO_2 and flow rate monitoring systems and measure CO_2 mass emissions at the bypass stack using the reference methods in §40 CFR Part 75.22(b) for CO_2 and flow rate and calculate CO_2 mass emissions for the unit as the sum of the emissions recorded by the installed monitoring systems on the main stack and the emissions measured by the reference method monitoring systems; or

(3) Install, certify, operate, and maintain CO_2 and flow rate monitoring systems only on the main stack. If this option is chosen, report the following values for each hour during which emissions pass through the bypass stack: the maximum potential concentration of CO_2 as determined under section 2.1.1.1 of Appendix A to §40 CFR Part 75—Specifications and Test Procedures (or, if available, the CO_2 concentration measured by a certified monitor located at the control device inlet may be reported instead), and the hourly volumetric flow rate value that would be substituted for the flow monitor installed on the main stack or flue under the missing data procedures in subpart D of §40 CFR Part 75—Missing Data Substitution Procedures if data from the flow monitor installed on the main stack or flue were missing for the hour. The maximum potential CO_2 concentration may be specific to the type of fuel combusted in the unit during the bypass (*see* §40 CFR Part 75.33(b)(5)). The option in this paragraph, (f)(3), may only be used if use of the bypass stack is limited to unit startup, emergency situations (e.g., malfunction of a flue gas desulfurization system), and periods of routine maintenance of the flue gas desulfurization system or maintenance on the main stack. Calculate CO_2 mass emissions for the unit as the sum of the emissions calculated with the substitute values and the emissions recorded by the CO_2 and flow monitoring systems installed on the main stack.

(g) *Unit with Multiple Stacks or Ducts.* When the flue gases from an affected unit utilize two or more ducts feeding into two or more stacks, or when the flue gases utilize two or more ducts feeding into a single stack and the owner or operator chooses to monitor in the ducts rather than the stack, the owner or operator shall either:

(1) Install, certify, operate, and maintain a CO_2 continuous emission monitoring system and flow monitoring system in each duct feeding into the stack or stacks and determine CO_2 mass emissions from each affected unit as the sum of the CO_2 mass emissions recorded for each duct; or

(2) Install, certify, operate, and maintain a CO_2 continuous emission monitoring system and flow monitoring system in each stack. Determine CO_2 mass emissions from each affected unit as the sum of the CO_2 mass emissions recorded for each stack. Notwithstanding the prior sentence, if another unit also exhausts flue gases to one or more of the stacks, the owner or operator shall also comply with the applicable common stack requirements of this section to determine and record CO_2 mass emissions from the units using that stack and shall calculate and report CO_2 mass emissions from the affected units and stacks, pursuant to an approach approved by the Director, such that these emissions are not underestimated.

O_2 Continuous Emission Monitoring Method:

(h) *O_2 CEMS*. An owner or operator that utilizes an O_2 continuous emission monitoring system and flow monitoring system to comply with the requirements established in subsection (a)(2) of Section 1, of this Chapter, shall comply with the applicable provisions specified in paragraph (j) through (n) of this Section.

(i) *Section (3)(b) Method*. The owner or operator shall meet the requirements of subsection (i) of this Section for each affected unit while the unit is combusting fuel. The owner or operator shall utilize the applicable provisions of the procedures established in paragraph (b) of Section 3 of this Chapter (Section 3(b) Method).

(j) *Moisture Correction.* Where O_2 concentration is measured on a dry basis, the owner or operator shall either:

(1) Report the appropriate fuel-specific default moisture value for each unit operating hour, selected from among the following: 3.0%, for anthracite coal; 6.0% for bituminous coal; 8.0% for sub-bituminous coal; 11.0% for lignite coal; 13.0% for wood and 14.0% for natural gas (boilers, only); or

(2) Install, operate, maintain, and quality assure a continuous moisture monitoring system for measuring and recording the moisture content of the flue gases, in order to correct the measured hourly volumetric flow rates for moisture when calculating CO_2 mass emissions (in lb/hr) using the procedures in Section 3 of this Chapter. The following continuous moisture monitoring systems are acceptable: a continuous moisture sensor; an oxygen analyzer (or analyzers) capable of measuring O_2 both on a wet basis and on a dry basis; or a stack temperature sensor and a moisture look-up table, i.e., a psychrometric chart (for saturated gas streams following wet scrubbers or other demonstrably saturated gas streams, only). The moisture monitoring system shall include as a component the automated data acquisition and handling system (DAHS) for recording and reporting both the raw data (e.g., hourly average wet-and dry-basis O_2 values) and the hourly average values of the stack gas moisture content derived from those data. When a moisture look-up table is used, the moisture monitoring system shall be represented as a single component, the certified DAHS, in the monitoring plan for the unit or common stack.

(k) *Common Stack Procedures.* The following procedures shall be used when more than one unit uses a common stack:

(1) *Unit utilizing common stack.* When an affected unit utilizes a common stack with one or more other affected units the owner or operator shall:

(i) Install, certify, operate, and maintain an O_2 continuous emission monitoring system and flow monitoring system in the duct to the common stack from each affected unit; or

(ii) Install, certify, operate, and maintain an O_2 continuous emission monitoring system and flow monitoring system in the common stack and combine emissions for the affected units for recordkeeping and compliance purposes.

(A) Combine emissions for the affected units for recordkeeping and compliance purposes; or

(B) Provide information satisfactory to the Director on methods for apportioning CO_2 mass emissions measured in the common stack to each of the affected units. The Director may approve such substitute methods for apportioning CO_2 mass emissions measured in a common stack whenever the method ensures complete and accurate accounting of all emissions regulated under this Section.

(l) *Unit with Bypass Stack.* Whenever any portion of the flue gases from an affected unit can be routed through a bypass stack so as to avoid the installed O_2 continuous emission monitoring system and flow monitoring system, the owner or operator shall either:

(1) Install, certify, operate, and maintain separate O_2 continuous emission monitoring systems and flow monitoring systems on the main stack and the bypass stack and calculate CO_2 mass emissions for the unit as the sum of the CO_2 mass emissions measured at the two stacks; or

(2) Monitor CO_2 mass emissions at the main stack using O_2 and flow rate monitoring systems and determine CO_2 mass emissions at the bypass stack using the reference methods in §40 CFR Part 75.22(b) for O_2 and flow rate and calculate CO_2 mass emissions for the unit as the sum of the emissions recorded by the installed monitoring systems on the main stack and the emissions measured by the reference method monitoring systems; or

(3) Install, certify, operate, and maintain O_2 and flow rate monitoring systems only on the main stack. If this option is chosen, report the following values for each hour during which emissions pass through the bypass stack: the maximum potential concentration of O_2 as determined under section 2.1.1.1 of Appendix A to §40 CFR Part 75—Specifications and Test Procedures (or, if available, the CO_2 concentration measured by a certified monitor located at the control device inlet may be reported instead), and the hourly volumetric flow rate value that would be substituted for the flow monitor installed on the main stack or flue under the missing data procedures in subpart D of §40 CFR Part 75—Missing Data Substitution Procedures if data from the flow monitor installed on the main stack or flue were missing for the hour. The maximum potential O_2 concentration may be specific to the type of fuel combusted in the unit during the bypass (*see* §40 CFR Part 75.33(b)(5)). The option in this paragraph, (f)(3), may only be used if use of the bypass stack is limited to unit startup, emergency situations (e.g., malfunction of a flue gas desulfurization system), and periods of routine maintenance of the flue gas desulfurization system or maintenance on the main stack. Calculate CO_2 mass emissions for the unit as the sum of the emissions calculated with the substitute values and the emissions recorded by the O_2 and flow monitoring systems installed on the main stack.

(m) *Unit with Multiple Stacks or Ducts.* When the flue gases from an affected unit utilize two or more ducts feeding into two or more stacks, or when the flue gases utilize two or more ducts feeding into a single stack and the owner or operator chooses to monitor in the ducts rather than the stack, the owner or operator shall either:

(1) Install, certify, operate, and maintain an O_2 continuous emission monitoring system and flow monitoring system in each duct feeding into the stack or stacks and determine CO_2 mass emissions from each affected unit as the sum of the CO_2 mass emissions recorded for each duct; or

(2) Install, certify, operate, and maintain an O_2 continuous emission monitoring system and flow monitoring system in each stack. Determine CO_2 mass emissions from each affected unit as the sum of the CO_2 mass emissions recorded for each stack. Notwithstanding the prior sentence, if another unit also exhausts flue gases to one or more of the stacks, the owner or operator shall also comply with the applicable common stack requirements of this section to determine and record CO_2 mass emissions from the units using that stack and shall calculate and report CO_2 mass emissions from the affected units and stacks, pursuant to an approach approved by the Director, such that these emissions are not underestimated.

CO_2 Mass Emissions from Low Mass Emissions Units:

(n) *Determination of CO_2 Mass Emissions from Low Mass Emissions Units*. The owner or operator of an affected unit that qualifies as a low mass emissions unit under §40 CFR Part 75.19(a) and (b) shall comply with one of the following:

(1) Meet the CO_2 Continuous Emissions Monitoring General Requirements in subsection (a)(1) or (a)(2) of Section 1 of this Chapter for a CO_2 continuous emission monitoring system and flow monitoring system;

(2) Meet the requirements specified in subsection (i) of this Section for use of the methods in Section 3 of this Chapter (Section 3(b) Method); or

(3) Use the low mass emissions methodology in subsection (c) of Section 3 of this Chapter for estimating hourly CO_2 mass emissions, if applicable under §40 CFR Part 75.19(a) and (b).

Section 3: CO_2 Determination Procedures

Determination of CO_2 Emissions - CO_2 Continuous Emission Monitoring Method:

(a) CO_2 Continuous Emission Monitoring Method - Determination of CO_2 Emissions. Use the following procedures to convert continuous emission monitoring system measurements of CO_2 concentration (percentage) and volumetric flow rate (scfh) into CO_2 mass emissions (in tons/day) when the owner or operator uses a CO_2 continuous emission monitoring system (consisting of a CO_2 monitor) and a flow monitoring system to monitor CO_2 emissions from an affected unit.

(1) When CO_2 concentration is measured on a wet basis, use the following equation to calculate hourly CO_2 mass emissions rates (in tons/hr):

(Equation a-1)

$$E_h = KC_hQ_h$$

Where:

E_h= Hourly CO_2 mass emission rate during unit operation, tons/hr.

K = $5.7\times10^{-7}$for CO_2, (tons/scf) /%CO_2.

C_h= Hourly average CO_2 concentration during unit operation, wet basis, either measured directly with a CO_2 monitor.

Q_h= Hourly average volumetric flow rate during unit operation, wet basis, scfh.

(2) When CO_2 concentration is measured on a dry basis, use the following equation to calculate hourly CO_2 mass emissions rates (in tons/hr):

(Equation a-2)

$$E_h = KC_{hp}Q_{hs}\frac{(100 - \%H_2O)}{100}$$

where:

E_h= Hourly CO_2 mass emission rate during unit operation, tons/hr.

K = $5.7\times10^{-7}$for CO_2, (tons/scf) percent CO_2.

C_{hp}= Hourly average CO_2 concentration in flue during unit operation, dry basis, percent CO_2.

Q_{hs}= Hourly average volumetric flow rate during unit operation, scfh as measured (wet).

%H_2O = Hourly average stack moisture content during unit operation, percent by volume.

(3) Use the following equations to calculate total CO_2 mass emissions for each calendar quarter (Equation a–3a) and for each calendar year (Equation a–3b):

(Equation a-3a)

$$E_{CO_2q} = \sum_{h=1}^{H_R} E_h t_h$$

Where:

E_{CO2q}= Quarterly total CO_2 mass emissions, tons.

E_h= Hourly CO_2 mass emission rate, tons/hr.

t_h=Unit operating time, in hours or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

H_R= Number of hourly CO_2 mass emission rates available during calendar quarter.

(Equation a-3b)

$$E_{CO_2a} = \sum_{q=1}^{4} E_{CO_2q}$$

Where:

E_{CO2a}= Annual total CO_2 mass emissions, tons.

E_{CO2q}= Quarterly total CO_2 mass emissions, tons.

q = Quarters for which E_{CO2q} are available during calendar year.

Determination of CO_2 Emissions - O_2 Continuous Emission Monitoring Method:

(b) O_2 Continuous Emission Monitoring Method - Determination of CO_2 Emissions. Use the following procedures to convert continuous emission monitoring system measurements of O_2 concentration (in percent by volume) and volumetric flow rate (scfh) into CO_2 mass emissions (in tons/day) when the owner or operator uses a O_2 continuous emission monitoring system and a flow monitoring system to monitor CO_2 emissions from an affected unit.

(1) When O_2 concentration is measured on a wet basis, use the following equation to calculate hourly CO_2 concentration (in percent by volume):

(Equation b-1)

$$CO_{2w} = \frac{100}{20.9}\frac{F_c}{F}\left[20.9\left(\frac{100-\%H_2O}{100}\right)-O_{2w}\right]$$

Where:

CO_{2w}= Hourly average CO_2 concentration during unit operation, percent by volume, wet basis.

O_{2w}= Hourly average O_2 concentration during unit operation, percent by volume, wet basis.

F, F_c= F-factor or carbon-based FC-factor from subsection (b)(5) of this Section.

20.9 = Percentage of O_2 in ambient air.

$\%H_2O$ = Moisture content of gas in the stack, percent.

For any hour where Equation b–1 results in a negative hourly average CO_2 value, 0.0% CO_{2w} shall be recorded as the average CO_2 value for that hour.

(2) When O_2 concentration is measured on a dry basis, use the following equation to calculate hourly CO_2 concentration (in percent by volume):

(Equation b-2)

$$CO_{2d} = 100\frac{F_c}{F}\frac{20.9-O_{2d}}{20.9}$$

Where:

CO_{2d}= Hourly average CO_2 concentration during unit operation, percent by volume, dry basis.

F, F_C= F-factor or carbon-based F_c-factor from subsection (b)(5) of this Section.

20.9 = Percentage of O_2 in ambient air.

O_{2d}= Hourly average O_2 concentration during unit operation, percent by volume, dry basis.

For any hour where Equation b–2 results in a negative hourly average CO_2 value, 0.0% CO_{2w} shall be recorded as the average CO_2 value for that hour.

(3) Determine CO_2 mass emissions (in tons) from hourly average CO_2 concentration (percent by volume) using Equation b–3, where O_2 measurements are on a wet basis.

(Equation b-3)

$$E_h = KC_hQ_h$$

Where:

E_h= Hourly CO_2 mass emission rate during unit operation, tons/hr.

K = $5.7\times10^{-7}$for CO_2, (tons/scf) /%CO_2.

C_h= Hourly average CO_2 concentration during unit operation, wet basis, either measured directly with a CO_2 monitor or calculated from wet-basis O_2 data using Equation b–1, percent CO_2.

Q_h= Hourly average volumetric flow rate during unit operation, wet basis, scfh.

(4) Determine CO_2 mass emissions (in tons) from hourly average CO_2 concentration (percent by volume) using Equation b–4, where O_2 measurements are on a dry basis.

(Equation b-4)

$$E_h = KC_{hp}Q_{hs}\frac{(100 - \%H_2O)}{100}$$

Where:

E_h= Hourly CO_2 mass emission rate during unit operation, tons/hr.

K =$5.7\times10^{-7}$for CO_2, (tons/scf) percent CO_2.

C_{hp}= Hourly average CO_2 concentration in flue, dry basis, percent CO_2.

Q_{hs}= Hourly average volumetric flow rate during unit operation, scfh as measured (wet).

%H_2O = Hourly average stack moisture content during unit operation, percent by volume.

(5) F, F_c=a factor representing a ratio of the volume of dry flue gases generated to the caloric value of the fuel combusted (F), and a factor representing a ratio of the volume of CO_2 generated to the calorific value of the fuel combusted (F_c), respectively. Table 1 lists the values of F and F_c for different fuels.

Table b-5. F - and F_c - Factors[1]

Fuel	F-factor (dscf/MMBtu)	F_C-factor (scf CO_2/MMBtu)
Coal (as defined by ASTM D388–99[2]):		
Anthracite	10,100	1,970
Bituminous	9,780	1,800
Subbituminous	9,820	1,840
Lignite	9,860	1,910
Petroleum Coke	9,830	1,850
Tire Derived Fuel	10,260	1,800
Oil	9,190	1,420
Gas:		
Natural gas	8,710	1,040
Propane	8,710	1,190
Butane	8,710	1,250
Wood:		
Bark	9,600	1,920
Wood residue	9,240	1,830

[1]Determined at standard conditions: 20 °C (68 °F) and 29.92 inches of mercury.
[2]Incorporated by reference under §75.6 of this part.

(6) Use the following equations to calculate total CO_2 mass emissions for each calendar quarter (Equation b–6a) and for each calendar year (Equation b–6b):

(Equation b-6a)

$$E_{CO_2q} = \sum_{h=1}^{H_R} E_h t_h$$

Where:

E_{CO2q}= Quarterly total CO_2 mass emissions, tons.

E_h= Hourly CO_2 mass emission rate, tons/hr.

t_h=Unit operating time, in hours or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

H_R= Number of hourly CO_2 mass emission rates available during calendar quarter.

(Equation b-3b)

$$E_{CO2a} = \sum_{q=1}^{4} E_{CO2q}$$

Where:

E_{CO2a}= Annual total CO_2 mass emissions, tons.

E_{CO2q}= Quarterly total CO_2 mass emissions, tons.

q = Quarters for which E_{CO2q} are available during calendar year.

Determination of CO_2 Emissions - Low Mass Emissions Units:

(c) Low Mass Emissions Methodology, Calculations, and Values

(1) Determination of CO_2 emission rates.

(i) If the unit combusts only natural gas and/or fuel oil, use Table c-1 of this subsection to determine the appropriate CO_2 emission factor for use in calculating hourly CO_2 mass emissions.

Table c-1 - CO_2 Emission Factors (ton/MMBtu) for Gas and Oil

Fuel Type	CO_2 Emission Factors
Pipeline (or other) Natural Gas	0.059 ton/MMBtu.
Oil	0.081 ton/MMBtu.

(ii) If the unit combusts a gaseous fuel other than pipeline natural gas or natural gas, the owner or operator shall determine a fuel-and-unit-specific CO_2 emission rate for the fuel, as follows:

(A) Derive a carbon-based F_c-factor for the fuel, using fuel sampling and analysis, as described in subsection (c)(2) of this Section; and

(B) Use Equation c–1 to derive the default CO_2 emission rate. Substitute the carbon-based F-factor determined in paragraph (1)(ii)(A) of this subsection into the equation to determine the default CO_2 emission rate for the unit.

(Equation c-1)

$$\frac{W_{CO_2}}{H} = \left(\frac{F_c \times U_f \times MW_{CO_2}}{2000} \right)$$

Where:

WCO_2/H= Ratio of CO_2 emitted to the hourly heat input from combustion, tons/MMBtu.

MW CO_2= Molecular weight of carbon dioxide, 44.0 lb/lb-mole.

F_c= Carbon based F-factor from (c)(1)(ii)(A).

Uf = 1/385 scf CO2/lb-mole at 14.7 psia and 68 °F.

(2) *Carbon-based F_c-factor*. Equation c–2b may be used in lieu of the factors determined in subsection (c)(3) of this Section to calculate a site-specific F_c factor (scf CO_2/MMBtu), on either a dry or wet basis. At a minimum, the site-specific F_c factor must be based on 9 samples of the fuel. Fuel samples taken during each run of a RATA are acceptable for this purpose. The site-specific F_c factor must be re-determined at least annually, and the value from the most recent determination must be used in the emission calculations. Alternatively, the previous F_c value may continue to be used if it is higher than the value obtained in the most recent determination. The owner or operator shall keep records of all site-specific F_c determinations, active for at least 3 years. (Calculate all F_c factors at standard conditions of 20 °C (68 °F) and 29.92 inches of mercury).

(Equation c–2b)

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

Where:

C = The content by weight of carbon (expressed as percent), as determined on the same basis as the gross calorific value (GCV) by ultimate analysis of the fuel combusted using ASTM D3176–89 (Reapproved 2002), Standard Practice for Ultimate Analysis of Coal and Coke, (solid fuels), ASTM D5291–02, Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants, (liquid fuels) or computed from results using ASTM D1945–96 (Reapproved 2001), Standard Test Method for Analysis of Natural Gas by Gas Chromatography, or ASTM D1946–90 (Reapproved 2006), Standard Practice for Analysis of Reformed Gas by Gas Chromatography, (gaseous fuels) as applicable.

GCV = The gross calorific value (Btu/lb) of the fuel combusted determined by ASTM D5865–01a, Standard Test Method for Gross Calorific Value of Coal and Coke, and ASTM D240–00, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter, or ASTM D4809–00, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method) for oil; and ASTM D3588–98, Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels, ASTM D4891–89 (Reapproved 2006), Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion, GPA Standard 2172–96 Calculation of Gross Heating Value, Relative Density and Compressibility Factor for Natural Gas Mixtures from Compositional Analysis, GPA Standard 2261–00 Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography, or ASTM D1826–94 (Reapproved 1998), Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter, for gaseous fuels, as applicable.

F_c value = For affected units that combust a combination of a fuel (or fuels) listed in Table c-2 in subsection (c)(3) of this Section with any fuel(s) not listed in Table c-2, the F_c value is subject to the Administrator's approval under §40 CFR Part 75.66.

F_c value = For affected units that combust combinations of fuels listed in Table c-2 in subsection (c)(3) of this Section, prorate the F_c factors determined by subsection (c)(2) or (c)(3) of this Section in accordance with the applicable formula as follows:

(Equation c-2c)

$$F_c = \sum_{t-1}^{n} X_i (F_c)_i$$

Where,

X_i= Fraction of total heat input derived from each type of fuel (*e.g.*, natural gas, bituminous coal, wood). Each X_i value shall be determined from the best available information on the quantity of fuel combusted and the GCV value, over a specified time period. The owner or operator shall explain the method used to calculate X_i in the hardcopy portion of the monitoring plan for the unit. The X_i values may be determined and updated either hourly, daily, weekly, or monthly. In all cases, the prorated F_c-factor used in the emission calculations shall be determined using the X_i values from the most recent update.

$(F_c)_i$= Applicable F_c factor for each fuel type determined in accordance with subsection (c)(2) or (c)(3) of this Section.

n = Number of fuels being combusted in combination.

As an alternative to prorating the F_c factor as described in this subsection, a “worst-case” F_c factor may be reported for any unit operating hour. The worst-case F_c factor shall be the highest F_c value for any of the fuels combusted in the unit.

(3) F_c= a factor representing a ratio of the volume of CO_2 generated to the calorific value of the fuel combusted (F_c), respectively. Table c-2 lists the values of F_c for different fuels.

Table c-2. F_c-Factors[1]

Fuel	F_C-factor (scf CO_2/MMBtu)
Coal (as defined by ASTM D388–99[2]):	
Anthracite	1,970
Bituminous	1,800
Subbituminous	1,840
Lignite	1,910
Petroleum Coke	1,850
Tire Derived Fuel	1,800
Oil	1,420
Gas:	
Natural gas	1,040
Propane	1,190
Butane	1,250
Wood:	
Bark	1,920
Wood residue	1,830

[1]Determined at standard conditions: 20 °C (68 °F) and 29.92 inches of mercury.
[2]Incorporated by reference under §40 CFR Part 75.6 of this part.

(4) *Heat input.* Hourly, quarterly and annual heat input for a low mass emissions unit shall be determined using the provisions established in §40 CFR Part 75.19(c)(3).

(5) *Calculation of CO_2 mass emissions.* The owner or operator shall, for the purpose of demonstrating that a low mass emissions unit meets the requirements of this Section, calculate CO_2 mass emissions in accordance with the following:

(i) *CO_2 Mass Emissions.*

(A) The hourly CO_2 mass emissions (tons) for the affected low mass emissions unit shall be determined using Equation c-5a and the appropriate fuel-based CO_2 emission factor from Table c-2 of this section for the fuel being combusted in that hour. If more than one fuel is combusted in the hour, use the highest emission factor for all of the fuels combusted in the hour. If records are missing as to which fuel was combusted in the hour, use the highest emission factor for all of the fuels capable of being combusted in the unit.

(Equation c-5a) $$W_{CO_2} = EF_{CO_2} \times HI_{hr}$$

Where:

WCO_2= Hourly CO_2mass emissions (tons).

EF CO_2= Either the fuel-based CO_2 emission factor from Table c-2 of this section or the fuel-and-unit-specific CO_2 emission rate from subsection (c)(1)(i) of this Section (tons/MMBtu).

HI_{hr}= Either the maximum rated hourly heat input or the hourly heat input as determined under subsection (c)(4) of this Section (MMBtu).

(B) The quarterly CO_2 mass emissions (tons) for the low mass emissions unit shall be the sum of all of the hourly CO_2 mass emissions in the quarter, as determined under subsection (c)(5)(i)(A)of this Section.

(C) The year-to-date cumulative CO_2 mass emissions (tons) for the low mass emissions unit shall be the sum of all of the quarterly CO_2 mass emissions, as determined under subsection (c)(5)(i)(B) of this Section, for all of the calendar quarters in the year to date.

Chapter 2

Level-2

Calculated CO_2 Emissions

Fuel Carbon Content Emissions Determination

Chapter 2 – Fuel Carbon Content Based CO_2 Emissions Determination

Background

Many affected units required to monitor under the provisions of §40 CFR Part 75 – Acid Rain utilize continuous emissions monitoring systems (CO_2 or O_2 CEMS) to track their CO_2 emissions. However, the requirements contained in §40 CFR Part 75 – Acid Rain also allow for determining CO_2 mass emissions based upon a fuel-use-based emissions calculation methodology. Therefore, owners or operators that utilize fuel-use-based calculations to determine CO_2 emissions to comply with the requirements of §40 CFR Part 75 – Acid Rain must use the procedures established in this Chapter. An owner or operator of an affected unit that is **not** required to monitor CO_2 under §40 CFR Part 75 – Acid Rain may use the procedures in this Chapter or Chapter 4 to determine CO_2 emissions.

Determining CO_2 emissions in accordance with §40 CFR Part 75.10(a)(3)(ii) (fuel Carbon content based emissions calculations) is designated a Level-2 method for measuring CO_2 emissions from an affected unit. Estimating CO_2 emissions from an affected unit using fuel use data generally involves the following three steps:

1. Determine annual consumption of each fuel combusted;
2. Determine the appropriate CO_2 emission factors for each fuel combusted; and
3. Calculate each fuel's corresponding CO_2 emissions.

Step 1: Determine annual consumption of each fuel combusted.
Identify all fuels combusted for each affected unit. Examples of fuel types include bituminous coal, residual fuel oil, distillate fuel (diesel), liquefied petroleum gas (LPG), and natural gas. Then determine the annual fuel use by fuel type, measured in terms of physical units (mass or volume). The preferred method is to determine the amount of fuel combusted at each unit by reading individual meters located at the fuel input point, if applicable. Alternatively, the owner or operator may use fuel receipts or purchase records to calculate the total fuel usage. Convert fuel purchase and storage data to estimates of measured fuel use using the following:

Total Annual Fuel Consumption = Annual Fuel Purchases + Fuel Stock at Beginning of Year – Fuel Stock at End of Year

Step 2: Determine the appropriate CO_2 emission factor for each fuel combusted.
The preferred method is to derive an emission factor for CO_2 using the measured characteristics of the fuels combusted. This method requires information on the heat content and/or carbon content of the fuel(s) combusted. This information can be determined either through fuel sampling and analysis or from data provided by fuel suppliers. The owner or operator must collect and analyze fuel data according to the requirements of this Chapter.

The carbon content of each fuel can be expressed in mass of carbon per mass of fuel (such as Lb C/ton), mass of carbon per volume of fuel (such as Lb C/gallon), or mass of carbon per unit energy of fuel (such as Lb C/MMBtu). The heat content of each fuel is expressed in units of energy per unit mass or volume (such as MMBtu/ton or MMBtu/gallon) and should be calculated based on higher heating values (HHV). Multiply the heat content per unit mass or volume (such as Btu/ton or Btu/gallon) by the carbon content per unit energy (e.g., Lb C/Btu) to determine the mass of carbon per physical unit of fuel (such as Lb C/ton or Lb C/gallon). If the measured carbon content data is expressed in mass of carbon per mass or volume of fuel, it is not necessary to multiply by a heat content factor, since the factor is already in physical units.

Step 3: Calculate each fuel's CO_2 emissions and convert to tons.
To determine CO_2 emissions from the affected unit, multiply the fuel use from Step 1 by the CO_2 emission factor from Step 2, and then convert pounds to tons. Repeat the calculation for each fuel type combusted, and then sum them for the total.

Section 1: Fuel Carbon Content Based CO_2 Emissions General Requirements

The owner or operator of an affected unit that is required to comply with the monitoring provisions established in §4O CFR Part 75 – Acid Rain, and/or the reporting provisions established in NAC 445B.XXX, and that utilizes the CO_2 monitoring method provided for in §40 CFR Part 75.10(a)(3)(ii) shall determine and report annual CO_2 emissions in accordance with the requirements established in Sections 1 through 3 of this Chapter. An owner or operator of an affected unit that is not required to comply with the monitoring provisions established in 4O CFR Part 75 - Acid Rain, may determine and report annual CO_2 emissions in accordance with the requirements established in Sections 1 through 3 of this Chapter, or with the procedures established in Chapter 4.

(a) *Primary Measurement Requirement.* The owner or operator shall measure CO_2 emissions for each affected unit by using the following method:

(1) The owner or operator shall determine CO_2 emissions based on the measured carbon content of the fuel and the procedures in Section 3 of this Chapter to estimate CO_2 emissions (in ton/day and tons/yr) discharged to the atmosphere.

(2) A single automated data acquisition and handling system may be used to meet the requirements of this Chapter.

(b) *Heat Input Rate Measurement Requirement.* The owner or operator shall determine and record the heat input rate, in units of MMBtu/hr, to each affected unit for every hour or part of an hour any fuel is combusted following the procedures in Appendix F to §40 CFR Part 75 – Conversion Procedures.

(c) *Minimum recording and recordkeeping requirements.* The owner or operator shall record and the responsible official shall report the hourly, daily, quarterly, and annual information collected under the requirements of this Section as specified in §40 CFR Part 75 Subpart F—Recordkeeping Requirements and Subpart G—Reporting Requirements.

Section 2: Fuel Carbon Content Based CO_2 Emissions Specific Provisions

CO_2 Emission Calculation – Fuel-Use-Based Method:

(a) An owner or operator that utilizes the fuel-use-based method to comply with the requirements established in Section 1 of this Chapter, shall follow the procedures in Section 3 of this Chapter for estimating daily CO_2 mass emissions based on the measured carbon content of the fuel and the amount of fuel combusted. For units with wet flue gas desulfurization systems or other add-on emissions controls generating CO_2, the owner or operator shall use the corresponding procedures in Section 3 of this Chapter to estimate both combustion-related emissions based on the measured carbon content of the fuel and the amount of fuel combusted and sorbent-related emissions based on the amount of sorbent injected. The owner or operator shall calculate daily, quarterly, and annual CO_2 mass emissions (in tons) in accordance with the procedures in Section 3 of this Chapter.

Section 3: CO_2 Fuel Carbon Content Based Determination Procedures

Determination of CO_2 Emissions – Fuel Carbon Content Based Calculation Method:

(a) *Fuel-Use-Based Method - Determination of CO_2 Emissions*. Use the following procedures to estimate CO_2 mass emissions discharged to the atmosphere (in tons/day) as the sum of CO_2 emissions from combustion and, if applicable, CO_2 emissions from sorbent used in a wet flue gas desulfurization control system, fluidized bed boiler, or other emissions control devices.

(1) *Procedures for Estimating CO_2 Emissions from Combustion.* Use the following procedures to estimate daily CO_2 mass emissions from the combustion of fossil fuels. The optional procedure in paragraph (3) of this subsection may also be used for an affected gas-fired unit. For an affected unit that combusts any non-fossil fuels (e.g., bark, wood, residue, or refuse), either use a CO_2 continuous emission monitoring system or apply to the Director for approval of a unit-specific method for determining CO_2 emissions.

(i) Use Equation a-1 to calculate daily CO_2 mass emissions (in tons/day) from the combustion of fossil fuels. Where fuel flow is measured in a common pipe header (i.e., a pipe carrying fuel for multiple units), the owner or operator may use the procedures in section 2.1.2 of Appendix D to §40 CFR Part 75 - Optional SO_2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units for combining or apportioning emissions, except that the term "SO_2 mass emissions" is replaced with the term "CO_2 mass emissions."

(ii) Collect at least one fuel sample during each week that the unit combusts coal, one sample per each shipment or delivery for oil and diesel fuel, one fuel sample for each delivery for gaseous fuel in lots, one sample per day or per hour (as applicable) for each gaseous fuel that is required to be sampled daily or hourly for gross calorific value under section 2.3.5.6 of Appendix D to §40 CFR Part 75 - Optional SO_2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units, and one sample per month for each gaseous fuel that is required to be sampled monthly for gross calorific value under section 2.3.4.1 or 2.3.4.2 of Appendix D to §40 CFR Part 75 - Optional SO_2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units. Collect coal samples from a location in the fuel handling system that provides a sample representative of the fuel bunkered or consumed during the week.

(iii) Determine the carbon content of each fuel sample using one of the following methods: ASTM D3178–89 (Reapproved 2002) or ASTM D5373–02 (Reapproved 2007) for coal; ASTM D5291–02, Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants, ultimate analysis of oil, or computations based upon ASTM D3238–95 (Reapproved 2000) and either ASTM D2502–92 (Reapproved 1996) or ASTM D2503–92 (Reapproved 1997) for oil; and computations based on ASTM D1945–96 (Reapproved 2001) or ASTM D1946–90 (Reapproved 2006) for gas.

(iv) Use daily fuel feed rates from company records for all fuels and the carbon content of the most recent fuel sample under this section to determine tons of carbon per day from combustion of each fuel. Where more than one fuel is combusted during a calendar day, calculate total tons of carbon for the day from all fuels.

(Equation a-1)

$$W_{CO_2} = \frac{(MW_c + MW_{O_2}) \times W_c}{2000\, MW_c}$$

Where:

Wco2=CO_2 emitted from combustion, tons/day.

MW_c=Molecular weight of carbon (12.0).

MW_{o2}=Molecular weight of oxygen (32.0)

W_c= Carbon burned, lb/day, determined using fuel sampling and analysis and fuel feed rates determined in subsection (a)(1)(ii) and (iii) of this Section.

(2)*Coal-fired Unit*. For an affected coal-fired unit, the estimate of daily CO_2 mass emissions given by Equation a-1 may be adjusted to account for carbon retained in the ash using the procedures in either paragraph (2)(i) through (2)(iii) or (2)(iv) of this subsection.

(i) Determine the ash content of the weekly sample of coal using ASTM D3174–00, "Standard Test Method for Ash in the Analysis Sample of Coal and Coke from Coal".

(ii) Sample and analyze the carbon content of the fly-ash according to ASTM D5373–02 (Reapproved 2007), Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal and Coke".

(iii) Discount the estimate of daily CO_2 mass emissions from the combustion of coal given by Equation a-1 by the percent carbon retained in the ash using the following equation:

(Equation a-2)

$$W_{NCO_2} = W_{CO_2} - \left(\frac{MW_{CO2}}{MW_c}\right)\left(\frac{A\%}{100}\right)\left(\frac{C\%}{100}\right)W_{COAL}$$

Where,

W_{NCO2}= Net CO_2 mass emissions discharged to the atmosphere, tons/day.

W_{CO2}= Daily CO_2 mass emissions calculated by Equation a-1, tons/day.

MW_{C02}= Molecular weight of carbon dioxide (44.0).

MW_c= Molecular weight of carbon (12.0).

A% = Ash content of the coal sample, percent by weight.

C% = Carbon content of ash, percent by weight.

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

(iv) The daily CO_2 mass emissions from combusting coal may be adjusted to account for carbon retained in the ash using the following equation:

(Equation a-3)

$$W_{NCO_2} = 0.99 W_{CO_2}$$

Where,

W_{NCO2}= Net CO_2 mass emissions from the combustion of coal discharged to the atmosphere, tons/day.

0.99 = Average fraction of coal converted into CO_2 upon combustion.

W_{CO2}= Daily CO_2 mass emissions from the combustion of coal calculated by Equation a-1, tons/day.

(3) In lieu of using the procedures, methods, and equations in paragraph (1)(i) of this subsection, the owner or operator of an affected gas-fired or oil-fired unit (as defined under §40 CFR Part 72.2) may use the following equation and records of hourly heat input to estimate hourly CO_2 mass emissions (in tons).

(Equation a-3)

$$W_{NCO_2} = \left(\frac{F_c \times H \times U_f \times MW_{CO_2}}{2000} \right)$$

Where:

WCO_2= CO_2 emitted from combustion, tons/hr.

MW CO_2= Molecular weight of carbon dioxide, 44.0 lb/lb-mole.

F_c= Carbon based F-factor, 1,040 scf/MMBtu for natural gas; 1,420 scf/MMBtu for crude, residual, or distillate oil; and calculated according to the procedures in paragraph (3)(i) of this subsection for other gaseous fuels.

H = Hourly heat input in MMBtu, as calculated using the procedures in section 5 of Appendix F to §40 CFR Part 75 – Conversion Procedures.

Uf = 1/385 scf CO2/lb-mole at 14.7 psia and 68 °F.

(i) F_c= a factor representing a ratio of the volume of CO_2 generated to the calorific value of the fuel combusted (F_c), respectively. Table a-3 lists the values of F_c for different fuels.

Table a-1. F- and F_c-Factors[1]

Fuel	F_C-factor (scf CO_2/MMBtu)
Coal (as defined by ASTM D388–99[2]):	
Anthracite	1,970
Bituminous	1,800
Subbituminous	1,840
Lignite	1,910
Petroleum Coke	1,850
Tire Derived Fuel	1,800
Oil	1,420
Gas:	
Natural gas	1,040

Propane	1,190
Butane	1,250
Wood:	
Bark	1,920
Wood residue	1,830

[1]Determined at standard conditions: 20 °C (68 °F) and 29.92 inches of mercury.
[2]Incorporated by reference under §40 CFR Part 75.6 of this part.

(4) *Procedures for Estimating CO_2 Emissions from Sorbent.* When the affected unit has a wet flue gas desulfurization system, is a fluidized bed boiler, or uses other emission controls with sorbent injection, use the procedures, methods, and equations in paragraphs (4)(i) through (4)(vi) of this subsection to determine daily CO_2 mass emissions from the sorbent (in tons).

(i) When limestone is the sorbent material, use the equations and procedures in either paragraph (4)(ii) or (iii) of this subsection.

(ii) Use the following equation to estimate daily CO_2 mass emissions from sorbent (in tons).

(Equation a-4)

$$SE_{CO_2} = W_{CaCO_3} F_u \frac{MW_{CO_2}}{MW_{CaCO_3}}$$

Where,

SE_{CO2}= CO_2 emitted from sorbent, tons/day.

W_{CaCO3}= $CaCO_3$ used, tons/day.

F_u= 1.00, the calcium to sulfur stoichiometric ratio.

MW_{CO2}= Molecular weight of carbon dioxide (44).

MW_{CaCO3}= Molecular weight of calcium carbonate (100).

(iii) In lieu of using Equation a-4, any owner or operator who operates and maintains a certified SO_2-diluent continuous emission monitoring system (consisting of an SO_2 pollutant concentration monitor and an O_2 or CO_2 diluent gas monitor), for measuring and recording SO_2 emission rate (in lb/MMBtu) at the outlet to the emission controls and who uses the applicable procedures, methods, and equations such as those in EPA Method 19 in Appendix A to §40 CFR Part 60—Specifications and Test Procedures to estimate the SO_2 emissions removal efficiency of the emission controls, may use the following equations to estimate daily CO_2 mass emissions from sorbent (in tons).

(Equation a-5)

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

Where,

SE_{CO2} =CO_2 emitted from sorbent, tons/day.

MW_{CO2} =Molecular weight of carbon dioxide (44).

MW_{SO2} =Molecular weight of sulfur dioxide (64).

W_{SO2} =Sulfur dioxide removed, lb/day, as calculated below using Eq. a-6.

F_u=1.0, the calcium to sulfur stoichiometric ratio.

and

(Equation a-6)

$$W_{SO_2} = SO_{2o} \frac{\%R}{(100 - \%R)}$$

Where:

WSO_2= Weight of sulfur dioxide removed, lb/day.

SO_{20}= SO_2 mass emissions monitored at the outlet, lb/day, as calculated using the equations and procedures in section 2 of Appendix F to §40 CFR Part 75 – Conversion Procedures.

%R = Overall percentage SO_2 emissions removal efficiency, calculated using equations such as those in EPA Method 19 in Appendix A to §40 CFR Part 60—Specifications and Test Procedures, and using daily instead of annual average emission rates.

(iv) When a sorbent material other than limestone is used, modify the equations, methods, and procedures in paragraph (4)(i) of this subsection as follows to estimate daily CO_2 mass emissions from sorbent (in tons).

(v) Determine a site-specific value for F_u, defined as the ratio of the number of moles of CO_2 released upon capture of one mole of SO_2, using methods and procedures satisfactory to the Administrator. Use this value of F_u (instead of 1.0) in either equation a–5 or equation a–6.

(vi) When using equation a–5, replace MW_{CaCO3}, the molecular weight of calcium carbonate, with the molecular weight of the sorbent material that participates in the reaction to capture SO_2 and that releases CO_2, and replace W_{CaCO3}, the amount of calcium carbonate used (in tons/day), with the amount of sorbent material used (in tons/day).

(5) *Procedures for Estimating Total CO_2 Emissions.* When the affected unit has a wet flue gas desulfurization system, is a fluidized bed boiler, or uses other emission controls with sorbent injection, use the following equation to obtain total daily CO_2 mass emissions (in tons) as the sum of combustion-related emissions and sorbent-related emissions.

(Equation a-7)

$$W_t = W_{CO_2} + SE_{CO_2}$$

Where,

W_t= Estimated total CO_2 mass emissions, tons/day.

W_{CO2}= CO_2 emitted from fuel combustion, tons/day, as determined in Equation a-1 of this Section.

SE_{CO2}= CO_2 emitted from sorbent, tons/day.

(6) *Missing Data Substitution Procedures for Fuel Analytical Data.* Use the following procedures to substitute for missing fuel analytical data used to calculate CO_2 mass emissions under this Section.

(i) Missing Carbon Content Data. Use the following procedures to substitute for missing carbon content data.

(ii) In all cases (i.e., for weekly coal samples or composite oil samples from continuous sampling, for oil samples taken from the storage tank after transfer of a new delivery of fuel, for as-delivered samples of oil, diesel fuel, or gaseous fuel delivered in lots, and for gaseous fuel that is supplied by a pipeline and sampled monthly, daily or hourly for gross calorific value) when carbon content data is missing, report the appropriate default value from Table a-2.

(iii) The missing data values in Table a-2 shall be reported whenever the results of a required sample of fuel carbon content are either missing or invalid. The substitute data value shall be used until the next valid carbon content sample is obtained.

Table a-2. – Missing Data Substitution Procedures – Missing Carbon Content

Parameter	Missing Data Value
Oil and Coal Carbon Content	The most recent, previous carbon content value available for that type of coal, grade of oil, or default value, in this Table.
Gas Carbon Content	The most recent, previous carbon content value available for that type of gaseous fuel, or default value, in this Table.
Default Coal Carbon Content	Anthracite: 90.0 percent
	Bituminous: 85.0 percent
	Subbituminous/Lignite: 75.0 percent
Default Oil Carbon Content	90.0 percent
Default Gas Carbon Content	Natural Gas: 75.0 percent
	Other Gaseous Fuels: 90.0 percent

(iv) *Gross Calorific Value Data.* For a gas-fired unit using the procedures of paragraph (3) of this subsection to determine CO_2 emissions, substitute for missing gross calorific value data used to calculate heat input by following the missing data procedures for gross calorific value in section 2.4 of Appendix D to §40 CFR Part 75 - Optional SO_2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units.

Chapter 3

Level-3

Calculated CO_2, CH_4 and N_2O Emissions

Fuel-Use-Based Emissions Determination

Chapter 3 – Fuel-Use-Based CO_2, CH_4 & N_2O Emissions Determination

Background

Estimating emissions for CO_2, CH_4 and N_2O can be determined based on a measurement of annual fuel consumption and a default emission factor.

Determining CO_2, CH_4 and N_2O emissions in accordance with fuel-use-based emissions calculations is designated a Level-3 method for determining these emissions from an affected unit. Estimating CO_2, CH_4 and N_2O emissions from an affected unit using fuel use data generally involves the following four steps:

1. Determine annual consumption of each fuel combusted;
2. Determine the appropriate CO_2, CH_4 and N_2O emission factors for each fuel combusted;
3. Calculate each fuel's corresponding CO_2, CH_4 and N_2O emissions; and
4. Convert CH_4 and N_2O emissions into CO_2 equivalent emissions.

Step 1: Determine annual consumption of each fuel combusted.
First, Identify all fuels combusted for each affected unit. Examples of fuel types include bituminous coal, residual fuel oil, distillate fuel (diesel), liquefied petroleum gas (LPG), and natural gas. Second, determine the annual fuel use by fuel type, measured in terms of physical units (mass or volume).

Step 2: Determine the appropriate CH_4 and N_2O emission factors for each fuel.
Estimating CO_2, CH_4 and N_2O emissions depends not only on fuel characteristics, but also on combustion technology and the associated combustion characteristics; usage of pollution control equipment; and maintenance and operational practices. Due to these complexities, estimates of CH_4 and N_2O emissions from affected units are much more uncertain than estimates of CO_2 emissions. CH_4 and N_2O also account for much smaller quantities of emissions from affected units than CO_2.

Step 3: Calculate each fuel's CO_2, CH_4 and N_2O emissions and convert to tons.
To determine the CO_2, CH_4 and N_2O emissions from an affected unit, multiply the fuel use from Step 1 by the CO_2, CH_4 or N_2O emission factor from Step 2, and then convert grams to tons.

Step 4: Convert CH_4 and N_2O emissions to units of CO_2 equivalent and determine total emissions.
Use the global warming potential factors to convert CH_4 and N_2O emissions to units of CO_2 equivalent (CO_{2e}). Then sum the emissions of all three gases to determine the total CO_{2e} emissions from each affected unit.

Section 1: Fuel-Use-Based CO_2, CH_4 & N_2O Emissions General Requirements

The owner or operator of an affected unit that is required to comply with the reporting provisions established in NAC 445B.XXX but does not utilize the procedures established in Chapters 1 or 2, shall determine and report annual CO_2, CH_4 and N_2O emissions in accordance with the requirements established in Sections 1 through 3 of this Chapter or with the procedures established in Chapter 4.

(a) *Primary Requirement.* The owner or operator shall determine CO_2, CH_4 and/or N_2O emissions for each affected unit by using the following method:

(1) The owner or operator shall determine CO_2, CH_4 and/or N_2O emissions based on fuel-use-based emissions calculations and the procedures in Sections 1 through 3 of this Chapter to estimate CO_2, CH_4 or N_2O emissions (in tons/yr) discharged to the atmosphere.

(b) *Annual Fuel Consumption of Fuel Combusted Measurement Requirement.* The owner or operator shall determine and record the amount of fuel or fuels combusted, in units of MMBtu/yr, for each affected unit following the procedures in Section 3(a)(1)(i) of this Chapter.

(c) *Minimum recording and recordkeeping requirements.* The owner or operator shall record and the responsible official shall report the hourly, daily, quarterly, and annual information collected under the requirements of this Section.

Section 2: Fuel-Use-Based CO_2, CH_4 or N_2O Emissions Specific Provisions

CO_2, CH_4 or N_2O Emission Determination – Fuel-Use-Based Method:

Determining CO_2, CH_4 and N_2O emissions in accordance with fuel-use-based emissions calculations is designated a Level-3 method for measuring these emissions from an affected unit. Estimating CO_2, CH_4 and N_2O emissions from an affected unit using fuel use data generally involves the following four steps:

(a) An owner or operator that utilizes the fuel-use-based method to comply with the annual reporting requirements established in Section 1 of this Chapter, shall follow the procedures in Section 3 of this Chapter for estimating CO_2, CH_4 and/or N_2O mass emissions based on the appropriate emission factor for the fuel and the amount of fuel combusted. The owner or operator shall calculate daily, quarterly, and annual CH_4 and/or N_2O mass emissions (in tons) in accordance with the procedures in Section 3 of this Chapter.

Section 3: CO_2, CH_4 and N_2O Fuel-Use-Based Determination Procedures

Determination of CO_2, CH_4 and/or N_2O Emissions – Fuel-Use-Based Calculation Method:

(a) *Fuel-Use-Based Method - Determination of CO_2, CH_4 and N_2O Emissions*. Use the following procedures to estimate CO_2, CH_4 *and* N_2O mass emissions discharged to the atmosphere as the sum of CO_2 equivalent (CO_{2e}) emissions (in tons/yr) from combustion.

(1) *Procedures for Estimating CO_2, CH_4 and N_2O Emissions from Combustion.* Use the following procedures to estimate annual CO_{2e} mass emissions from the combustion of fossil fuels.

(i) *Determine annual consumption of each fuel combusted.* Identify all fuels combusted in each affected unit during the reporting period. Determine the annual fuel use by fuel type, measured in units of mass or volume. The preferred method is to determine the amount of fuel combusted at each unit by reading individual meters located at the fuel input point, if available. If a measured heat content factor for a specific fuel is available, use the specific heat content factor to convert fuel data to energy units. Alternatively, the owner or operator may use fuel receipts or purchase records to calculate the total fuel usage. If fuel receipts or purchase records are utilized, convert fuel purchase and storage data to estimates of measured fuel use using the following:

Total Annual Fuel Consumption = Annual Fuel Purchases + Fuel Stock at Beginning of Year – Fuel Stock at End of Year

Convert the total fuel consumption into units of MMBtu for each fuel combusted based upon the heat content values provided for in Table 3-1..

(ii) *Determine the appropriate CO_2, CH_4 and N_2O emission factors for each fuel*. Utilize the appropriate default emission factors from Table 3-1 or 3-2. If an owner or operator uses direct monitoring to obtain specific emission factors based on periodic exhaust sampling, the procedures contained in Chapter 4 should be utilized.

Table 3-1 Default Factors for Calculating CO_2 Emissions from Fossil Fuel Combustion

Fuel Type	Level-3 Method		
	Heat Content	Carbon Content (Per Unit Energy)	Fraction Oxidized
Coal and Coke	MMBtu/Short Ton	Kg C/MMBtu	
Anthracite Coal	25.09	28.26	1.0
Bituminous Coal	24.93	25.49	1.0
Sub-bituminous Coal	17.25	26.48	1.0
Lignite	14.21	26.30	1.0
Coke	24.80	31.00	1.0
Natural Gas	BTU/Standard Cubic Foot	Kg C/MMBtu	
975 to 1,000 Btu/SCF	975 – 1,000	14.73	1.0
1,000 to 1,025 Btu/SCF	1,000 – 1,025	14.43	1.0
1,025 to 1,050 Btu/SCF	1,025 – 1,050	14.47	1.0
1,050 to 1,075 Btu/SCF	1,050 – 1,075	14.58	1.0
1,075 to 1,100 Btu/SCF	1,075 – 1,100	14.65	1.0
Greater than 1,100 Btu/SCF	>1,100	14.92	1.0
Unspecified (Weighted U.S. Average	1,029	14.47	1.0
Petroleum Products	MMBtu/Barrel	Kg C/MMBtu	
Distillate Fuel Oil (#1, 2 & 4)	5.825	19.95	1.0
Residual Fuel Oil (#5 & 6)	6.287	21.49	1.0
Crude Oil	5.800	20.33	1.0
LPG (average for fuel use)	3.849	17.23	1.0
Propane	3.824	17.20	1.0

Source: U.S. EPA, *Inventory of Greenhouse Gas Emissions and Sinks: 1990-2005* (2007), Annex 2.1, Tables A-31, A-32, A-35, and A-36, except: heat content factors for Unspecified Coal (by sector), Naphtha (<401 deg. F), and Other Oil (>401 deg. F) (from U.S. Energy Information Administration, *Annual Energy Review 2006* (2007), Tables A-1 and A-5) and Carbon Content and Heat Content factors for Coke and LPG (from EPA Climate Leaders, Stationary Combustion Guidance (2007), Table B-1). A fraction oxidized value of 1.00 is from the Intergovernmental Panel on Climate Change (IPCC), *Guidelines for National Greenhouse Gas Inventories* (2006). Note: Default CO_2 emission factors (per unit energy) are calculated as: Carbon Content × Fraction Oxidized × 44/12. Default CO_2 emission factors (per unit mass or volume) are calculated using Equation 12d: Heat Content × Carbon Content × Fraction Oxidized × 44/12 × Conversion Factor (if applicable). Heat content factors are based on higher heating values (HHV).

Table 3-2 Default CH_4 and N_2O Emission Factors

Fuel Type and Basic Technology	Configuration	CH_4 (g/MMBtu)	N_2O (g/MMBtu)
Liquid Fuels			
Residual Fuel Oil/Shale Oil Boilers	Normal Firing	0.8	0.3
	Tangential Firing	0.8	0.3
Gas/Diesel Oil Boilers	Normal Firing	0.9	0.4
	Tangential Firing	0.9	0.4
Large Diesel Oil Engines>600hp (447kw)		4.0	N/A
Solid Fuels			
Pulverized Bituminous Combustion Boilers	Dry Bottom, Wall Fired	0.7	0.5
	Dry Bottom, Tangentially Fired	0.7	1.4
	Wet Bottom	0.9	1.4
Bituminous Spreader Stoker Boilers	With and Without Re-injection	1.0	0.7
Bituminous Fluidized Bed Combustor	Circulating Bed	1.0	61.1
	Bubbling Bed	1.0	61.1
Bituminous Cyclone Furnace		0.2	1.6
Lignite Atmospheric Fluidized Bed		N/A	71.2
Natural Gas			
Boilers		0.9	0.9
Gas-Fired Gas Turbines >3MW		3.8	0.9
Large Dual-Fuel Engines		245	N/A
Combined Cycle		0.9	2.8
Peat			
Peat Fluidized Bed Combustor	Circulating Bed	3.0	7.0
	Bubbling Bed	3.0	3.0
Biomass			
Wood/Wood Waste Boilers		9.3	5.9
Wood Recovery Boilers		0.8	0.8

Source: IPCC, Guidelines for National Greenhouse Gas Inventories (2006), Chapter 2: Stationary Combustion, Table 2.6. Values were converted back from LHV to HHV using IPCC's assumption that LHV are 5 percent lower than HHV for coal and oil, 10 percent lower for natural gas, and 20 percent lower for dry wood. (The IPCC converted the original factors from units of HHV to LHV, so the same conversion rates were used here to obtain the original values in units of HHV. For purposes of reporting, the conversion factor of 20 percent for wood should not be used to convert between LHV and HHV values; instead you should use a value of 5 percent. Refer to the box on "Estimating Emissions Based on Higher Heating Values" in Section 12.2.) Values were converted from kg/TJ to g/MMBtu using 1 kg = 1000 g and 1 MMBtu = 0.001055 TJ. NA = data not available.

(iii) *Calculate each fuel's CH_4 and N_2O emissions.* Determine the CH_4 and N_2O emissions for each fuel combusted from an affected unit utilizing Equations a-1 and a-3.

(Equation a-1)

$$E_{CO_2} = \frac{F_{comb} \times EF_{CO_2}}{907.18}$$

Where:

E_{CO2}= Emissions of CH_4 in tons.

F_{Comb}= Annual total of fuel combusted in MMBtu.

EF_{CO2} = Emission factor in Kg-CH_4/MMBtu.

(Equation a-2)

$$E_{CH_4} = \frac{F_{comb} \times EF_{CH_4}}{907{,}180}$$

Where:

E_{CH4}= Emissions of CH_4 in tons.

F_{Comb}= Annual total of fuel combusted in MMBtu.

EF_{CH4} = Emission factor in g-CH_4/MMBtu.

(Equation a-1)

$$E_{N_2O} = \frac{F_{comb} \times EF_{N_2O}}{907{,}180}$$

Where:

E_{N2O}= Emissions of N_2O in tons.

F_{Comb}= Annual total of fuel combusted in MMBtu.

EF_{N2O} = Emission factor in g-N_2O/MMBtu.

(iv) *Convert CH_4 and N_2O emissions to units of CO_2 equivalent*. Use the global warming potential factors provided below to convert the CH_4 and N_2O emissions determined in Equation a-2 and a-3 of this Section to units of CO_{2e}.

CO_2 Emissions = 1 CO_{2e}

CH_4 Emissions = 21 CO_{2e}

N_2O Emissions = 310 CO_{2e}

(v) Sum the emissions of all CO_{2e} gases to determine the total annual CO_2 emissions from each affected unit.

Chapter 4

Level-2.5

(Optional)
Calculated CO_2, CH_4 and N_2O Emissions

Performance Test Based Emission Determination

Chapter 4 (Optional) – Performance Test Based Emissions Determination

Background

As discussed in previous Chapters, most affected units are required to continuously monitor CO_2 emissions under the CEMS requirements of §40 CFR Part 75 – Acid Rain. The Acid Rain requirements also allow for determining CO_2 mass emissions based upon a fuel-use-based emissions calculation methodology. Methane (CH_4) and Nitrous Oxide (N_2O) are not pollutants that are routinely monitored by CEMS. Therefore, CEMS based emissions data for these two pollutants are not likely to be available. Chapters 2 and 3 provide procedures for determining GHG emissions based on a fuel-use-based methodologies. However, estimating GHG emissions can also be accomplished by utilizing emissions data obtained from performance testing conducted on an affected unit.

In some cases more accurate emissions estimates may be developed for a particular affected unit by utilizing actual emissions test data as the basis for emissions calculations. This can be particularly helpful if an affected unit's emissions are not measured by a CEMS and when fuel-use-based emissions estimations are not as reliable because of a particular combustion technology or emissions control system. Performance test data may also be more reliable in situations were a unique fuel or blended fuels may be combusted. Periods were a backup fuel or a fuel that is used infrequently may also benefit from basing GHG emissions estimations on actual emissions test data.

Determining CO_2, CH_4 and N_2O emissions based on performance test data is designated a Level-2 method for determining these emissions from an affected unit. Estimating CO_2, CH_4 and N_2O emissions from an affected unit using actual emissions test data generally involves the following four steps:

1. Conduct a performance test, or series of tests, to obtain actual flue gas emissions data;
2. Determine annual consumption of fuel(s) combusted and hours of operation;
3. Develop an appropriate CO_2, CH_4 and/or N_2O emission factor based on the test data;
4. Calculate each units corresponding CO_2, CH_4 and/or N_2O emissions; and
5. Convert CH_4 and N_2O emissions into CO_2 equivalent emissions.

Step 1: Conduct performance test to obtain flue gas emissions data.
A performance test must be performed to obtain actual flue gas data for CO_2, CH_4 and/or N_2O. Prior to any testing, an emissions test protocol must be submitted and approved by the Director.

Step 2: Determine annual fuel consumption and hours of operation.
Identify all fuels combusted for each affected unit. Determine the annual fuel use by fuel type, measured in terms of physical units (mass or volume). Identify annual hours of operation that correspond to the operational conditions of the performance test(s).

Step 3: Develop an appropriate CO_2, CH_4 and N_2O emission factor based on the test data.
Utilize the performance test data to derive an emission factor in terms of LB/MMBtu or Lb/hr.

Step 4: Calculate CO_2, CH_4 and N_2O emissions and convert to tons.
To determine the CO_2, CH_4 and N_2O emissions from an affected unit by multiply the fuel use or hours of operation determined in Step 2 by the corresponding CO_2, CH_4 or N_2O emission factor from Step 2, and then convert to tons.

Step 5: Convert CH_4 and N_2O emissions to units of CO_2 equivalent and determine total emissions.
Use the global warming potential factors to convert CH_4 and N_2O emissions to units of CO_2 equivalent (CO_{2e}). Then sum the emissions of all three gases to determine the total CO_{2e} emissions from each affected unit.

Section 1: Performance Test Based CO_2, CH_4 & N_2O Emissions General Requirements

The owner or operator of an affected unit that is required to comply with the reporting provisions established in NAC 445B.XXX may utilize the procedures established in this Chapter if not otherwise required to utilize the procedures in Chapter 1, or 2. The owner or operator may determine and report annual CO_2, CH_4 and N_2O emissions in accordance with the requirements established in Sections 1 through 3 of this Chapter 4. The provisions of this Chapter may also be utilized to supplement the emissions information determined in Chapters 1 through 3 above.

(a) *Optional Requirement.* The owner or operator may determine CO_2, CH_4 and/or N_2O emissions for each affected unit by using the following method:

(1) The owner or operator shall determine CO_2, CH_4 and/or N_2O emissions based on performance test based emissions calculations and the procedures in Sections 1 through 3 of this Chapter to estimate CO_2, CH_4 or N_2O emissions (in tons/yr) discharged to the atmosphere.

(b) *Annual Fuel Consumption Measurement Requirement.* The owner or operator shall determine and record the amount of fuel or fuels combusted, in units of MMBtu, and the corresponding hours of operation, in hours, for each affected unit following the procedures in Section 3(a)(1)(i) of this Chapter.

(c) *Minimum recording and recordkeeping requirements.* The owner or operator shall record and the responsible official shall report the hourly, daily, quarterly, and annual information collected under the requirements of this Section.

Section 2: Performance Test Based CO_2, CH_4 or N_2O Emissions Specific Provisions

CO_2, CH_4 or N_2O Emissions Determination – Performance Test Based Method:

Determining CH_4 and N_2O emissions in accordance with fuel-use-based emissions calculations is designated a Level-2 method for measuring these emissions from an affected unit. Estimating CH_4 and N_2O emissions from an affected unit using fuel use data generally involves the following four steps:

(a) An owner or operator that utilizes the fuel-use-based method to comply with the annual reporting requirements established in Section 1 of this Chapter, shall follow the procedures in Section 3 of this Chapter for estimating CO_2, CH_4 and/or N_2O mass emissions based on the appropriate emission factor for the fuel and the amount of fuel combusted. The owner or operator shall calculate daily, quarterly, and annual CO_2, CH_4 and/or N_2O mass emissions (in tons) in accordance with the procedures in Section 3 of this Chapter.

Section 3: CO_2, CH_4 and N_2O Performance Test Based Determination Procedures

Determination of CO_2, CH_4 and/or N_2O Emissions – Performance Test Based Calculation Method:

(a) Performance-Test-Based Method - Determination of CO_2, CH_4 and N_2O Emissions. Use the following procedures to estimate CO_2, CH_4 and N_2O mass emissions discharged to the atmosphere as the sum of CO_2 equivalent (CO_{2e}) emissions (in tons/yr) from combustion.

(1) *Procedures for Estimating CO_2, CH_4 and N_2O Emissions from Combustion.* Use the following procedures to estimate annual CO_{2e} mass emissions from the combustion of fossil fuels.

(i) *Performance testing*. Conduct a performance test, or series of performance tests, to determine the emissions of CO_2, CH_4 and N_2O in LB/MMBtu. Each performance test must be approved in advance by the Director in accordance with the provisions established in NAC 445B.252. Unless otherwise approved in advance by the Director, each performance test, or series of performance test, shall only be applicable for the reporting year that the test is conducted in.

(ii) *Determine annual fuel consumption of each fuel combusted.* Identify all fuels combusted in each affected unit during the reporting period. Determine the annual fuel use by fuel type, measured in units of mass or volume. The preferred method is to determine the amount of fuel combusted at each unit by reading individual meters located at the fuel input point, if available. If a measured heat content factor for a specific fuel is available, use the specific heat content factor to convert fuel data to energy units. Alternatively, the owner or operator may use fuel receipts or purchase records to calculate the total fuel usage. If fuel receipts or purchase records are utilized, convert fuel purchase and storage data to estimates of measured fuel use using the following:

Total Annual Fuel Consumption = Annual Fuel Purchases + Fuel Stock at Beginning of Year – Fuel Stock at End of Year

Convert the total fuel consumption into units of MMBtu for each fuel combusted.

(iii) *Derive CO_2, CH_4 and/or N_2O emission factors.* Emission factors for CO_2, CH_4 and/or N_2O shall be obtained from the results of each valid performance test or series of performance tests. The owner or operator of an affected unit may request approval from the Director to utilize an emission factor that is based on multiple valid performance tests, such that the approved factor may be utilized for reporting periods that a performance test is not conducted in.

(iv) *Calculate CO_2, CH_4 and N_2O emissions.* Determine the CO_2, CH_4 and N_2O emissions for each fuel combusted from an affected unit utilizing Equations a-1 through a-3.

(Equation a-1)

$$E_{CO_2} = \frac{F_{comb} \times EF_{CO_2}}{907{,}180}$$

Where:

E_{CO2}= Emissions of CH_4 in tons.

F_{Comb}= Annual total of fuel combusted in MMBtu.

EF_{CO2} = Emission factor in LB-CH_4/MMBtu.

(Equation a-2)

$$E_{CH_4} = \frac{F_{comb} \times EF_{CH_4}}{907{,}180}$$

Where:

E_{CH4}= Emissions of CH_4 in tons.

F_{Comb}= Annual total of fuel combusted in MMBtu.

EF_{CH4} = Emission factor in LB-CH_4/MMBtu.

(Equation a-3)

$$E_{N_2O} = \frac{F_{comb} \times EF_{N_2O}}{907{,}180}$$

Where:

E_{N2O}= Emissions of N_2O in tons.

F_{Comb}= Annual total of fuel combusted in MMBtu.

EF_{N2O} = Emission factor in LB-N_2O/MMBtu.

(v) *Convert CO_2, CH_4 and N_2O emissions to units of CO_2 equivalent*. Use the global warming potential factors provided below to convert the CO_2, CH_4 and N_2O emissions determined in Equation a-1 and a-2 of this Section to units of CO_{2e}.

CO_2 Emissions = 1 CO_{2e}

CH_4 Emissions = 21 CO_{2e}

N_2O Emissions = 310 CO_{2e}

(vi) Sum the emissions of all CO_{2e} gases to determine the total annual CO_2 emissions from each affected unit.

Chapter 5

Emissions Allocations

Cogeneration Units
Combined Heat & Power Units

Chapter 5 – Allocating Emissions from Combined Heat & Power Units

Background

For Combined Cycle System configurations, all GHG emissions produced by combustion in the combustion turbine, and any emissions from duct firing, must be monitored and reported. For Cogeneration System configurations, all GHG emissions produced by combustion in the affected unit utilized for electrical generation purposes will be considered as emissions associated with the affected unit. Heat utilized for non-electrical generating purposes must be subtracted out of the emissions total.

Accounting for the GHG emissions from a Combined Heat and Power (CHP) unit is unique because it produces more than one useful product from the same amount of fuel combusted, namely, electricity and heat or steam. As such, apportionment of the GHG emissions between the two different energy streams may be useful. Note that to comply with Registry reporting guidelines, Reporters must only determine absolute emissions from a CHP plant using the same procedure for non-CHP plants described in the previous section. However, Reporters may also allocate emissions according to each final product stream, i.e. electricity or steam, as described in this section. Note that a CHP facility refers to a system that captures the waste-heat from the primary electricity generating pathway and uses it for non-electricity purposes. In contrast, a combined cycle power plant that uses waste heat to generate electricity should be treated no differently from stationary combustion emissions as described in the previous section. The most consistent approach for allocating GHG emissions in CHP applications is the efficiency method, which allocates emissions of CHP plants between electric and thermal outputs on the basis of the energy input used to produce the separate steam and electricity products. To use this method, you must know the total emissions from the CHP plant, the total steam (or heat) and electricity production, and the steam (or heat) and electricity efficiency of the facility. Use the following steps to determine the share of emissions attributable to steam (or heat) and electricity production.

Step 1: Determine the total direct emissions from the CHP system.
Calculate total direct GHG emissions using the methods described in the previous section. Like the guidance for non-CHP stationary combustion, calculating total emissions from CHP sources is based on either CEMS, fuel data or performance testing.

Step 2: Determine the total steam and electricity output for the CHP system.
To determine the total energy output of the CHP plant attributable to steam production, use published tables that provide energy content (enthalpy) values for steam at different temperature and pressure conditions (for example, the *Industrial Formulation 1997 for the Thermodynamic Properties of Water and Steam* published by the International Association for the Properties of Water and Steam (IAPWS)). Energy content values multiplied by the quantity of steam produced at the temperature and pressure of the CHP plant yield energy output values in units of MMBtu. Alternatively, determine net heat (or steam) production (in MMBtu) by subtracting the heat of return condensate (MMBtu) from the heat of steam export (MMBtu). To convert total electricity production from MWh to MMBtu, multiply by 3.412 MMBtu/MWh.

Step 3: Determine the efficiencies of steam and electricity production.
Identify steam (or heat) and electricity production efficiencies. If actual efficiencies of the CHP plant are not known, use a default value of 80 percent for steam and a default value of 35 percent for electricity. The use of default efficiency values may, in some cases, violate the energy balance constraints of some CHP systems. However, total emissions will still be allocated between the energy outputs. If the constraints are not satisfied, the efficiencies of the steam and electricity can be modified until constraints are met.

Step 4: Determine the fraction of total emissions allocated to steam and electricity production.
Allocate the emissions from the CHP plant to the steam and electricity product streams by using Equation a-1 and a-2.

(Equation a-1)

$$E_H = (H \div e_H) \div [(H \div e_H) + (P \div e_P)] \times E_T$$

(Equation a-2) $$E_P = E_T - E_H$$

Where:
EH = Emissions allocated to steam production;
H = Total steam (or heat) output (MMBtu);
eH = Efficiency of steam (or heat) production;
P = Total electricity output (MMBtu);
eP = Efficiency of electricity generation;
ET = Total direct emissions of the CHP system; and
EP = Emissions allocated to electricity production.