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Greenhouse Gas Reporting in the Ethylene Manufacturing Sector

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Abstract: The Greenhouse Gas (GHG) Mandatory Reporting Rule (MRR), codified in Part 98 of Title 40 of the Code of Federal Regulations, requires numerous manufacturing sectors including ethylene manufacturing plants in the U.S. to report actual GHG emissions from applicable facilities starting with reporting year 2010. This paper describes the types of GHG emission sources at ethylene plants that are subject to the GHG MRR requirements and the different calculation methodologies and monitoring options that are allowed for reporting emissions from such sources. This paper describes the procedures that are required to quality assure the data used for estimating emissions. The paper also focuses on options provided within the GHG MRR that can be utilized to reduce the incremental data collection and quality assurance burden for ethylene plants to streamline GHG reporting.

Introduction

The United States Environmental Protection Agency (EPA) published the final Greenhouse Gas (GHG) Mandatory Reporting Rule (MRR) in the Federal Register at 40 Code of Federal Regulations (CFR) Part 98. The EPA has relatively straightforward objectives in developing this rulemaking. The Agency wanted to address a substantial portion of nationwide GHG emissions, limit the impact on small businesses, and generate data that would be useful in establishing GHG mitigation policies in the future. To meet these objectives, the EPA developed a rule that specifies the industrial sectors that will be covered and the emission calculation methodologies that must be used.

As with most Clean Air Act regulations, questions have arisen on the GHG MRR concerning key applicability provisions such as the universe of equipment at affected facilities that may be subject and the emission calculation methodologies that should be applied. The discussion contained in this paper focuses on the final version of the GHG MRR, as of January 1, 2011. There were numerous updates to definitions, calculation methodologies, and monitoring, recordkeeping, and reporting provisions that were finalized and are effective for the first reporting year. These updates are contained as part of the material presented in this paper and are required for the first reporting year, unless otherwise noted. The first report is due on March 31, 2011, for reporting year 2010. The EPA has developed the Electronic GHG Reporting Tool (e-GGRT) for reporting data. Please note that there are some data requirements that do not have to be reported until August 31, 2011. These are found in Table A-6 of Subpart A.

40 CFR Part 98 establishes mandatory GHG reporting requirements for owners and operators of certain facilities that directly emit GHG, as well as for fossil fuel suppliers and industrial GHG suppliers. GHGs are defined to include the following pollutants: carbon dioxide (CO₂), methane (CH₄), nitrous oxide (N₂O), sulfur hexafluoride (SF₆), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and other fluorinated GHGs. GHG emissions are converted into a comparable value by using a carbon dioxide equivalent (CO₂e). CO₂e is the number of metric tons of CO₂ emissions with the same global warming potential as one metric ton of another greenhouse gas. In general, there are four criteria which must be used to determine whether a facility is subject to the reporting requirements under the GHG MRR. These are as follows:

- A facility that contains any of the source categories listed in Table 1 below starting in 2010 (Additional categories were added to this list for the 2011 reporting year, but are not found in the table);

Table 1. Source Category List

Source Categories Applicable in 2010 and Future Years
Electricity generation (units that report CO ₂ mass emissions year-round under 40 CFR 75)
Adipic acid production
Aluminum production
Ammonia manufacturing
Cement production
HCFC-22 production
HFC-23 production processes not collocated with a HCFC-22 production facility and that destroy more than 2.14 metric tons of HFC-23 per year
Lime manufacturing
Nitric acid production
Petrochemical production
Petroleum refineries
Phosphoric acid production
Silicon carbide production
Soda ash production
Titanium dioxide production
Municipal solid waste landfills that generate greater than 25,000 metric tons CO ₂ e (from CH ₄) per year
Manure management systems with combined CH ₄ and N ₂ O emissions in amounts equivalent to greater than 25,000 metric tons CO ₂ e per year

- A facility that contains any source category that is listed in Table 2 below and that emits 25,000 metric tons CO₂e or more per year in combined emissions from stationary fuel combustion units, miscellaneous uses of carbonate, and all applicable source categories listed in Tables 1 and 2 (Additional categories were added to the list for the 2011 reporting year, but are not found in the table);

Table 2. Source Category List

Source Categories Applicable in 2010 and Future Years
Ferroalloy production
Glass production
Hydrogen production
Iron and steel production
Lead production
Pulp and paper production
Zinc production

- A facility that does not meet the requirements listed above, but for which the aggregate maximum rated capacity of the stationary fuel combustion units at the facility is greater than or equal to 30 MMBtu/hr and where the facility emits 25,000 metric tons CO₂e or more per year in combined emissions from stationary fuel combustion units; or
- A supplier that is listed in Table 3 (Additional categories were added to this list for the 2011 reporting year, but are not found in the table).

Table 3. Supplier Category List

Supplier Categories Applicable in 2010 and Future Years
Coal-to-liquids suppliers
Petroleum product suppliers
Natural gas and natural gas liquids suppliers
Industrial greenhouse gas suppliers
Carbon dioxide suppliers

An ethylene production facility is considered part of the "Petrochemical Production" source category; therefore, ethylene producers fall into the GHG MRR under the first criteria mentioned above. By definition in Part 98, petrochemical means methanol, acrylonitrile, ethylene, ethylene oxide, ethylene dichloride, and any form of carbon black. The source category includes processes that produce these chemicals as either intermediates or final products. If these chemicals are produced only as a by-product, they are not part of the source category. For an ethylene production facility, the annual GHG report must cover stationary fuel combustion sources per the requirements found in Subpart C and all applicable source categories from Tables 1 and 2 above. For an ethylene production facility, there is no threshold level of CO₂e emissions that must be considered to determine whether the facility needs to submit an inventory under 40 CFR Part 98; therefore, all ethylene production facilities are subject to these requirements.

Calculating GHG Emissions under 40 CFR Part 98 for Ethylene Production Facilities

Ethylene production facilities must follow the procedures listed in Subpart C for Stationary Combustion Sources and Subpart X for Petrochemical Production to calculate GHG emissions. Process emissions of CO₂, CH₄, and N₂O must be reported. The CO₂ generated by reaction in the process and by combustion of process off-gas in stationary combustion units and flares must be reported. Combustion emissions (CO₂, CH₄, N₂O) from stationary combustion units must also be reported (to account for the combustion of supplemental fuel such as natural gas or fuel used for the flare pilot and flare sweep gas). If CO₂ is captured at

the facility, the procedures in Subpart PP, for Suppliers of CO₂, must be followed to report the mass of CO₂ captured.

There are two options given for calculating GHG emissions from ethylene production facilities, the mass balance methodology (as found in 98.243(c)) or the combustion methodology (as found in 98.243(d)). A third methodology is required if all process vents and emissions from the combustion of process off-gas are routed to one or more stacks equipped with a continuous emissions monitoring system (CEMS) (except flare stacks). In this case, the process-based emissions must be determined through the use of the CEMS (as found in 98.243(b)). Most facilities do not have CEMS currently in place on all their process vents; therefore, this methodology will not be addressed in further detail in this paper. A facility should review its existing monitoring and recordkeeping practices to determine which methodology should be employed.

Mass Balance Option Calculation Methodology

The mass balance option calculation methodology is available to all facilities that are considered part of the "Petrochemical Production" source category. Under the mass balance option, emissions of CO₂ for each petrochemical process unit must be calculated for each month. CO₂, CH₄, and N₂O combustion emissions must be reported according to the requirements of Subpart C, but only for the combustion of supplemental fuel so that emissions are not double-counted. Subpart C contains a tiered calculation approach, which depends on existing monitoring being done, as well as the type of supplemental fuel used. The tiered calculation approach of Subpart C is discussed further in the next section, as it forms the basis for the combustion option calculation methodology.

For gaseous and liquid feedstocks (ie, ethane, propane, naphtha, etc.) and products (ie, ethylene, propylene, aromatic compounds, etc.), the volume or mass used or produced for each calendar month must be measured with a flow meter. A product is defined as each of the carbon-containing outputs from a process and includes the petrochemical, recovered byproducts, and liquid organic wastes that are not incinerated on-site. The flow meter must follow certain procedures to assure data quality and the calibration method specified by the manufacturer or an industry consensus standard must be used. The GHG MRR provides the accuracy specification depending on type of flow meter. The calibration and quality assurance requirements are discussed in detail in a separate section of this report as the requirements apply to all flow meters required by the GHG MRR. The GHG MRR also provides that flow meters must be recalibrated at the minimum frequency specified by the manufacturer, biennially, or at the interval specified by the industry consensus standard. Alternatively, for liquids, the volume can be calculated based on measurements of the liquid level in the storage tank at least once per month (and just prior to each change in direction of level of liquid). The tank level measurements must be performed using a consensus-based standard or a standard industry practice.

Under the mass balance option, the carbon content of each feedstock and product must be determined each month according to the specific ASTM standards or methods listed in the GHG MRR or by using a gas chromatographic/mass spectrometer analysis provided the instrument is operated, maintained, and calibrated according to the manufacturer's instructions. Additionally, modifications of existing applicable methods may be used if none of the listed methods is appropriate. The equipment must be calibrated according to the specific standard or method used. Supplier analyses may also be used, but they must still comply with the quality assurance requirements of the GHG MRR. If multiple valid carbon content measurements are made, the arithmetic average of the results should be used. If feedstock is delivered in lots, and if multiple deliveries from the same supply source are received in a calendar month, only one representative sample is required. If the monthly average concentration of a specific compound in a feedstock or product is determined to be greater than 99.5% by mass (or volume for gases), then the carbon content can be calculated assuming 100% of the feedstock or product is the specific compound during periods of normal operation. Records should be maintained supporting this determination. If off-specification products are produced, this assumption may not be used. If any process changes are made that affect this assumption, then records must be kept of the composition determination.

The net carbon input or output from gaseous feedstocks and products are calculated using the following equation (as found in 98.243(c)(5)(i) - Equation X-1):

$$C_g = \sum_{n=1}^{12} \left[\sum_{i=1}^j F_{gf, i, n} * CC_{gf, i, n} * \frac{MW_{f, i}}{MVC} - \sum_{i=1}^k P_{gp, i, n} * CC_{gp, i, n} * \frac{MW_{p, i}}{MVC} \right]$$

where:

C_g = Annual net contribution to calculated emissions from carbon in gaseous materials (kg/yr)

$(F_{gf})_{i, n}$ = Volume of gaseous feedstock i introduced in month "n" (scf)

$(CC_{gf})_{i, n}$ = Average carbon content of gaseous feedstock i for month "n" (kg C per kg of feedstock)

$(MW_f)_i$ = Molecular weight of gaseous feedstock i (kg/kg-mole)

MVC = Molar volume conversion factor (849.5 scf per kg-mole at 68°F and 14.7 pounds per square inch absolute or 836.6 scf/kg-mole at 60°F and 14.7 pounds per square inch absolute)

$(P_{gp})_{i, n}$ = Volume of gaseous product i produced in month "n" (scf)

$(CC_{gp})_{i, n}$ = Average carbon content of gaseous product i, including streams containing CO₂ recovered for sale or use in another process, for month "n" (kg C per kg of product)

$(MW_p)_i$ = Molecular weight of gaseous product i (kg/kg-mole)

j = Number of feedstocks

k = Number of products

The net carbon input or output from the liquid feedstocks and products are calculated using the following equation (as found in 98.243(c)(5)(ii) - Equation X-2):

$$C_i = \sum_{n=1}^{12} \left[\sum_{i=1}^{j \text{ or } k} (F_{if})_{i,n} * (CC_{if})_{i,n} - (P_{ip})_{i,n} * (CC_{ip})_{i,n} \right]$$

where:

C_i = Annual net contribution to calculated emissions from carbon in liquid materials, including liquid organic wastes (kg/yr)

$(F_{if})_{i,n}$ = Volume or mass of liquid feedstock i introduced in month "n" (gallons or kg)

$(CC_{if})_{i,n}$ = Average carbon content of liquid feedstock i for month "n" (kg C per gallon or kg of feedstock)

$(P_{ip})_{i,n}$ = Volume or mass of liquid product i produced in month "n" (gallons or kg)

$(CC_{ip})_{i,n}$ = Average carbon content of liquid product i, including organic liquid wastes, for month "n" (kg C per gallon or kg of product)

j = Number of feedstocks

k = Number of products

The annual CO₂ mass emissions are calculated using the following equation (as found in 98.243(c)(5)(iv) – Equation X-4):

$$CO_2 = 0.001 * 44/12 * (C_g + C_l)$$

where:

CO₂ = Annual CO₂ mass emissions from process operations and process off-gas combustion (metric tons/year)

0.001 = Conversion factor from kg to metric tons

44 = Molecular weight of CO₂ (kg/kg-mole)

12 = Atomic weight of carbon (C) (kg/kg-mole)

The mass balance calculation option allows a facility to calculate CO₂ emissions by evaluation of carbon containing feedstocks and products. A separate calculation is required to account for GHG emissions from supplemental fuel (ie, natural gas used for combustion sources or for the flare pilot), unlike the combustion option, which allows process off-gas and supplemental fuel to be considered together under a streamlined approach. The combustion option calculation methodology is discussed in the next section.

Combustion Option Calculation Methodology

Unlike the mass balance option calculation methodology, the combustion option calculation methodology is only available to ethylene production facilities. If the combustion option calculation methodology is used, the calculated CO₂, CH₄, and N₂O emissions for each stationary combustion source and flare that burns any amount of petrochemical process off-gas must be reported under Subpart X, which refers to the methodologies of Subpart C that apply. In addition, CO₂, CH₄, and N₂O emissions from stationary combustion units must be

reported separately, using the requirements of Subpart C, if the units only burn supplemental fuel.

Subpart C contains a hierarchy of methods to calculate GHG emissions from stationary fuel gas combustion devices. A direct measurement approach, one where the unit has a continuous emissions monitor for CO₂, is Tier 4, and requires the most rigorous monitoring. Tier 3 and Tier 2 use both the combination of direct fuel measurement and the application of fuel-specific factors. The least rigorous tier is Tier 1, which uses fuel consumption records combined with default factors.

To calculate CO₂ emissions for each combustion source that burns any amount of petrochemical process off-gas, the Tier 3 or Tier 4 calculation methodology must be used, except as specified below, which allows reporting using the simplified Tier 1 or Tier 2 calculation methodology under certain instances. Each stationary combustion unit that burns ethylene process off-gas is not required to use the same tier for calculation. To calculate emissions from the combustion of any ethylene process off-gas streams, Tier 1 and Equation C-1 (which uses annual volume of fuel combusted from company records, a default higher heating value (HHV) of fuel, and a fuel-specific CO₂ emission factor) or Tier 2 and Equation C-2a (which uses the annual volume of fuel combusted from company records, the annual average HHV of the fuel calculated using specific methods, and a fuel specific default CO₂ emission factor from Subpart C) can be used if either of the following two conditions are met.

- If the annual average flow rate of fuel gas (that contains ethylene process off-gas) in the fuel gas line to the combustion unit, prior to any split to individual burners or ports, does not exceed 345 ft³/min at 60 deg F and 14.7 psia, this option for calculating CO₂ emissions can be used. A flow meter must not be installed at any point in the line supplying fuel gas or an upstream common pipe. The annual average flow rate should come from company records and assume that total flow is evenly distributed over 525,600 min/yr.
- If the combustion unit has a maximum rated heat input capacity of less than 30 MMBtu/hr and a flow meter is not installed at any point in the line supplying fuel gas (containing ethylene process off-gas) or an upstream common pipe, this calculation option can be used.

When using the Tier 4 calculation methodology, annual emissions of CO₂ from all fuels combusted are calculated based on quality-assured data from a continuous emissions monitor (CEMs). A concentration monitor and stack gas volumetric flow rate monitor must be installed and specific calculation methodologies must be used. The Tier 3 calculation methodology uses the annual volume of fuel combusted measured directly using calibrated flow meters or fuel billing meters (which do not apply in the case of ethylene production facilities because the fuel gas is a mixture of process off-gas and other supplemental fuel). The carbon content and molecular weight of the fuel is also required, where the annual average is calculated in accordance with Tier 3 of Subpart C. The minimum required sampling frequency is specified in

the GHG MRR and the method for computing the annual average is a function of the unit size and how frequently the carbon content sampling is performed (i.e. monthly or more frequently, or less frequently than monthly). Fuel flow meters that measure mass flow for liquid or gaseous fuels may be used provided the fuel density is used to convert the readings to volumetric flow rates. The density shall be measured at the same frequency as the carbon content using a consensus-based standard or standard industry practice.

Emissions of CH₄ and N₂O should be calculated using the same tier methodology that is used for calculating CO₂ emissions. For gaseous fuels that contain ethylene process off-gas, default emission factors should be used. For Tier 3 calculation methodologies, default emission factors for the HHV of fuel gas should be used, or a calculated HHV should be used.

A separate calculation methodology for flares is found under the combustion option calculation methodology, unlike the mass balance option calculation methodology. For flares, emissions of CO₂, CH₄, and N₂O should be calculated using the methodology found in Subpart Y (98.253(b)(1) through (b)(3)). If the flare has a continuous flow meter, then the measured rates must be used provided the monitor is operational and the flow rate is within the calibrated range of the measurement device. If no continuous flow meter is available, if the monitor is not operational, or if the flow rate is outside the calibrated range, use of engineering calculations, company records, or similar estimates of volumetric flare gas flow is required. If there is a continuous HHV monitor or gas composition monitor on the flare, or if these parameters are monitored at least weekly, the value should be used to calculate CO₂ emissions. If HHV or carbon content is not measured at least weekly, an alternative method can be used, where the quantity of gas discharged must be determined separately for periods of routine operation and periods of startup, shutdown, or malfunction. For periods of startup, shutdown, or malfunction, engineering calculations and process knowledge should be used to estimate the carbon content of the flared gas for each event exceeding 500,000 scf/day. For normal operation, the average HHV measured for the fuel gas should be used for the HHV of the flare gas and if the value is not measured, then historic data or engineering calculations should be used. Separate equations are given for the calculation of CH₄ and N₂O emissions from flaring.

Since the GHG calculation options for ethylene production facilities differ, there are differences in monitoring, recordkeeping, and reporting requirements as well.

Monitoring and Quality Assurance Requirements

The EPA's MRR contains numerous monitoring requirements to assure the data reported is of good quality. Many facilities had to install new flow meters and put additional procedures in place to meet the requirements of the GHG MRR. As part of the GHG MRR, the EPA has developed extensive procedures for estimating missing data for elements such as feedstock flow rates, product flow rates, and carbon content. During the first quarter of 2010, facilities

were able to use best available monitoring methods (BAMM) for any parameter that could not reasonably be measured according to the monitoring and QA/QC requirements of the relevant subpart(s). These methods include those currently used by the facility (if they did not meet the specifications of a relevant subpart) and also include supplier data, engineering calculations, or other company records. The EPA approved requests for BAMM if it was determined the facility could not reasonably acquire, install, and operate a required piece of monitoring equipment by April 1, 2010. Using BAMM is not approved beyond December 31, 2010, unless a process unit shutdown is needed and in this case special approval criteria apply.

As mentioned previously, there are specific calibration and accuracy requirements for flow meters required by the GHG MRR. The requirements do not depend on the calculation methodology chosen but instead on the type of instrument used to measure the flow. Flow meters measuring liquid and gaseous fuel feed rates, process stream flow rates, or feedstock or product flow rates are included in these requirements. The instruments must be calibrated by using the appropriate manufacturer's recommended procedures, an appropriate industry consensus standard method, or a method specified in a relevant subpart. Other measurement devices must be calibrated to meet the accuracy requirements in the applicable subpart or must be calibrated to an accuracy range within the appropriate error range for the specific measurement technology.

Calibration error should be calculated using the provisions given in the GHG MRR. For orifice, nozzle, and venturi flow meters, the initial quality assurance consists of in-situ calibration of the differential pressure, total pressure, and temperature transmitters. In cases where there are only two transmitters in the immediate vicinity of the flow meter's primary element, there is no need to install or calibrate an additional transmitter. Instead, the facility may use assumed values for temperature and/or total pressure, based on measurements of these parameters at a remote location, provided that when appropriate correction factors are applied they accurately represent the actual temperature or total pressure at the flow meter at all expected ambient conditions and that all temperature and/or total pressure measurements are made with calibrated gauges, sensors, transmitters, or other appropriate measurement devices. The instruments should be calibrated within the appropriate error range for the specific measurement technology, according to the manufacturer's specification, or per an industry consensus standard.

Mathematical correlations must be used to convert remote temperature or total pressure readings, or both, to the actual temperature or total pressure at the flow meter on a daily basis and the correlations must be adjusted annually to ensure accuracy. Actual temperature and total pressure should be used to correct the measured flow rates to standard conditions. Fuel billing meters are exempt from the calibration requirements provided the fuel supplier and any unit combusting the fuel do not have any common owners and are not owned by subsidiaries or affiliates of the same company. Feedstock billing meters are not exempt. Meters that are used exclusively for unit startup are exempted from the calibration requirements. If the calibration results show the necessary accuracy specifications are not

met, then missing data procedures should be used starting with the hour of the missed calibration.

Specific monitoring and quality assurance requirements for measuring HHV or carbon content were previously discussed under the specific calculation methodology. Data reporting requirements depend on the calculation methodology chosen.

Data Reporting Requirements

If using the mass balance methodology, the following information must be reported: petrochemical process unit ID, type of petrochemical produced, names of other products, names of carbon-containing feedstocks, annual CO₂ emissions, monthly volume, mass, and carbon content values used in the calculation, the molecular weights for gaseous feedstocks and products used in the calculation, temperature at which the gaseous feedstocks and product volumes were determined, whether an alternative sampling or analysis method was used, the annual quantity of each type of petrochemical produced from each unit (metric tons), the name of each method used to determine a measured parameter or a description of that method, ID of each unit that burned both process off-gas and supplemental fuel, and details if complying with alternative sampling and analysis methods. A facility can separately report the flow and carbon content of wastewater and annual mass of carbon released in fugitive emissions and process vents that are not controlled with a combustion device. The values can be estimated based on engineering analysis and are not to be used in the mass balance calculation. There are additional data reporting requirements for facilities using alternative methods for determination of carbon content and molecular weight.

If using the combustion methodology, the following information must be reported for each applicable reporting tier: the ethylene process unit ID and for each stationary combustion unit that burns ethylene process off-gas (or group of sources with a common pipe), except flares, the relevant information such as unit ID, code representing type of unit, maximum rated heat input capacity of unit, type of fuel combusted in unit during the year, and tier used to calculate CO₂ emissions for each type of fuel combusted. Facilities using Tiers 1-3 should report annual CO₂ mass emissions and annual CH₄ and N₂O mass emissions for each type of fuel combusted. Facilities using Tier 4 should report the total annual CO₂ mass emissions, estimate of heat input from each type of fuel listed, and annual CH₄ and N₂O emissions for each of these fuels. An estimate based on engineering judgment of the fraction of total emissions attributable to the combustion of off-gas from the ethylene process unit, information listed in 98.256(e) of Subpart Y for each flare burning ethylene process off-gas, name and annual quantity of each feedstock, and the annual quantity of ethylene produced from each process unit should also be reported for this calculation methodology.

All facilities must report the following information: facility name, physical street address of the facility, year and months covered by the report, date of submittal, annual emissions of

CO₂, CH₄, and N₂O from all applicable source categories in terms of CO₂e, and annual emissions of each GHG from each applicable source category reported separately. In addition, the report must specify whether reported emissions include a cogeneration unit, and for suppliers, the annual CO₂, CH₄, and N₂O from combustion or use of the products supplied, imported, and exported during the year. Reporting requirements also include a written explanation if the calculation methodology has changed throughout the year, a brief description of BMM, parameter measured if using BMM, and time period during which BMM was used. Each data element for which a missing data procedure was used and the total number of hours for which the missing data procedure was used should also be reported, along with the following general information: signed and dated certification statement, NAICS code(s) that apply to the facility's primary product/activity and other associated NAICS code(s) (as applicable), the legal names and addresses of the parent company, and the percentage of ownership interest for each.

Recordkeeping Requirements

The recordkeeping requirements depend on the calculation methodology chosen. If the facility complies with the mass balance methodology, the following records must be kept: the results of feedstock or product composition determinations, start and end times and calculated carbon contents for time periods when off-specification product is produced, and if an alternative methodology for determining carbon content is used, the estimated accuracy of measurement devices, the technical basis for these estimates, and the dates and results of the calibrations for each measurement device. If the facility complies with the optional combustion methodology, the records required for the applicable Tier calculation methodologies must be kept in addition to the annual average flow calculations.

The following general recordkeeping requirements apply: a list of all units, operations, processes and activities for which GHGs were calculated, data used to calculate GHG emissions for fuel or material type including calculations and methods used, analytical results for development of site-specific emission factors, results of analyses for HHV, carbon content, and other required fuel or feedstock parameters, and any other facility operating data or process information. Records of annual GHG reports, results of certification and quality assurance tests of continuous monitoring systems, fuel flow meters, and other instrumentation used to provide data, maintenance records for all continuous monitoring systems, flow meters, and other instrumentation used to provide data should be kept as well. Records must be maintained for each missing data event, and include the cause of the event and the corrective actions taken to restore the malfunctioning monitoring equipment.

A written monitoring plan is also required for all facilities reporting under the GHG MRR. The monitoring plan should contain the following items: identification of persons of responsibility for collection of emissions data, explanation of processes and methods used to collect necessary data for the calculations, and a description of methods and procedures used

for quality assurance, maintenance, and repair of all continuous monitoring systems, flow meters, and other instrumentation used to provide data.

Options Utilized to Reduce Burden on Ethylene Production Facilities

The combustion option calculation methodology was published in the final GHG MRR to reduce the burden on ethylene production facilities. The final GHG MRR contains this option because nearly all process emissions are from the combustion of process off-gas; therefore, all combustion units burning process off-gas (with or without supplemental fuel) can use the procedures of Subpart C to calculate GHG emissions. The estimated emissions for the combustion option calculation methodology include all stationary combustion units including those supplying energy to processes other than the ethylene production process. The combustion methodology requires separate reporting of GHG emissions from flares, while the mass balance methodology does not. Use of the Tier 3 methodology requires measurement of the total fuel flow and relatively frequent measurement of the carbon content of the fuel. Smaller units are allowed to use the Tier 1 or Tier 2 reporting requirements under the combustion calculation option if a flow meter is not installed. Tier 1 or Tier 2 reporting under the combustion methodology is only allowed if there is not an existing flow meter. If a flow meter is in place, then the flow meter would have to be calibrated and Tiers 3 or 4 used. Certain reporting alternatives exist under Subpart C, which would allow a facility to further group emissions for reporting purposes, such as the "aggregation of units" provisions if the units are less than 250 MMBtu/hr or if a "common pipe" exists. Aggregation would allow a cost savings with respect to the installation of additional monitoring equipment if the group meets the requirements of the GHG MRR. Under the combustion calculation option, the aggregation could include both off-gas and supplemental fuel, if it was combusted together in a unit. Separate emission estimates are required for units combusting only supplemental fuel. Under the material balance option, if natural gas is used as a supplemental fuel and billing records are provided in therms or MMBtu, then Tier 1 and aggregation of all units using the fuel could be considered a "common pipe" group regardless of unit size.

Conclusion

The GHG MRR requires many facilities to install additional flow meters, to analyze additional composition parameters (carbon content, HHV) on existing feedstock, product, or fuel lines, or to implement additional quality assurance (calibration, accuracy determination) procedures at a facility. Most facilities chose their calculation methodology based on a review of existing flow meters and analytical sampling procedures and the gaps existing between current practices and the requirements of the GHG MRR. Facilities also took into account the time for implementation of the GHG MRR (if BMM would not extend beyond December 31,

2010) and whether it was feasible to get the new monitoring equipment or instrumentation installed in a timely manner.

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