



Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments

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**Subpart X—Petrochemical
Production**

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Subpart X—Petrochemical Production

**U. S. Environmental Protection Agency
Office of Atmospheric Programs
Climate Change Division
Washington, D.C.**

FOREWORD

This document provides EPA's responses to public comments on EPA's Proposed Mandatory Greenhouse Gas Reporting Rule. EPA published a Notice of Proposed Rulemaking in the Federal Register on April 10, 2009 (74 FR 16448). EPA received comments on this proposed rule via mail, e-mail, facsimile, and at two public hearings held in Washington, DC and Sacramento, California in April 2009. Copies of all comments submitted are available at the EPA Docket Center Public Reading Room. Comments letters and transcripts of the public hearings are also available electronically through <http://www.regulations.gov> by searching Docket ID *EPA-HQ-OAR-2008-0508*.

Due to the size and scope of this rulemaking, EPA prepared this document in multiple volumes, with each volume focusing on a different broad subject area of the rule. This volume of the document provides EPA's responses to significant public comments received for 40 CFR Part 98, Subpart X—Petrochemical Production.

Each volume provides the verbatim text of comments extracted from the original letter or public hearing transcript. For each comment, the name and affiliation of the commenter, the document control number (DCN) assigned to the comment letter, and the number of the comment excerpt is provided. In some cases the same comment excerpt was submitted by two or more commenters either by submittal of a form letter prepared by an organization or by the commenter incorporating by reference the comments in another comment letter. Rather than repeat these comment excerpts for each commenter, EPA has listed the comment excerpt only once and provided a list of all the commenters who submitted the same form letter or otherwise incorporated the comments by reference in table(s) at the end of each volume (as appropriate).

EPA's responses to comments are generally provided immediately following each comment excerpt. However, in instances where several commenters raised similar or related issues, EPA has grouped these comments together and provided a single response after the first comment excerpt in the group and referenced this response in the other comment excerpts. In some cases, EPA provided responses to specific comments or groups of similar comments in the preamble to the final rulemaking. Rather than repeating those responses in this document, EPA has referenced the preamble.

While every effort was made to include significant comments related to 40 CFR Part 98, Subpart X—Petrochemical Production in this volume, some comments inevitably overlap multiple subject areas. For comments that overlapped two or more subject areas, EPA assigned the comment to a single subject category based on an assessment of the principle subject of the comment. For this reason, EPA encourages the public to read the other volumes of this document with subject areas that may be relevant to 40 CFR Part 98, Subpart X—Petrochemical Production.

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SUBPART X—PETROCHEMICAL PRODUCTION

1. DEFINITION OF SOURCE CATEGORY

Commenter Name: Sarah B. King

Commenter Affiliation: DuPont Company

Document Control Number: EPA-HQ-OAR-2008-0508-0604.1

Comment Excerpt Number: 46

Comment: It appears in this subpart that EPA does not incorporate provisions to account for use of biobased feedstocks in the production of chemicals that have been routinely produced from fossil based energy. To the extent bio-based feedstocks are utilized in the production of petrochemicals either independently or in combination with fossil based feedstocks, it is recommended that EPA in some manner allow for documentation of the quantity of fossil-energy based CO₂ emissions avoided by utilization of the bio-based feedstocks. This methodology could incorporate determination of net emissions or a credit for avoided fossil-based CO₂ emissions. This issue may also be applicable to other subparts of the rule and GHG reporting process, and EPA is urged to consider whether any other changes are similarly appropriate.

Response: Subpart X, like other subparts in part 98, is a reporting rule, primarily focused on anthropogenic emissions. It is not a crediting system for reduced emissions or avoided emissions. Furthermore, to our knowledge there is no commercial petrochemical production using bio-based feedstocks in the U.S. Available information suggests that existing bio-based processes overseas or under development are independent of processes with fossil-based feedstock (e.g., production of ethylene via steam cracking of fossil-based feedstock versus dehydration of bio-based ethanol feedstock). However, if the processing steps were to remain the same with only a change from fossil-based to bio-based feedstock, we consider the production using bio-based feedstock to be a separate process from production using fossil-based feedstock. To clarify the scope of subpart X, section 98.240(f) of the final rule specifies that production of a petrochemical in a process that uses bio-based feedstock is not part of the petrochemical production source category.

Commenter Name: See Table 2

Commenter Affiliation:

Document Control Number: EPA-HQ-OAR-2008-0508-0433.2

Comment Excerpt Number: 42

Comment: Ethylene production should be removed from the definition of the petrochemical production source category. Ethylene production facilities do not produce CO₂ emissions other than from combustion sources as part of the production process as, for example, ethylene oxide process do. In addition, other sources of CO₂e emissions from ethylene processes such as flaring and wastewater treatment are typically much less than 1% of total CO₂e emissions. This is recognized by EPA in the technical support document for the petrochemical production sector, page 5, “All of the GHG emissions associated with the ethylene process are from combustion units.” Greenhouse gas emissions from an ethylene facility's combustion sources would be estimated according to the requirements specified in subpart C of the rule even if ethylene was not included in the petrochemical production source category. Ethylene production facilities

would all still be captured by other reporting thresholds in section 98.2. This would be true even if the CO₂e reporting threshold was raised from 25,000 tons to 100,000 tons. Inclusion of ethylene in the petrochemical production source category only creates confusion over the rule requirements. As indicated above, nearly all the greenhouse gas emissions come from combustion sources that would be reported under subpart C whether or not ethylene was included in the petrochemical source category definition. In addition, the option of using a mass balance approach to determine CO₂e emissions from an ethylene unit makes no sense. Ethylene production units have no normal process vents and CO₂ is not produced in the ethylene production process. This makes the mass balance approach irrelevant and confusing. It is therefore recommended that ethylene production be removed from the definition of the petrochemical production source category.

Response: Please see Section III.X.3 of the preamble for the response to this comment.

Commenter Name: Robert Rouse

Commenter Affiliation: The Dow Chemical Company

Document Control Number: EPA-HQ-OAR-2008-0508-0533.1

Comment Excerpt Number: 30

Comment: GHG emissions associated with ethylene production are dominated by combustion sources (i.e., cracking furnaces). Therefore, Dow suggests that EPA formally remove ethylene production plants from Subpart X and clearly state that the combustion emissions must be reported under Subpart C. Methane is also produced within ethylene production plants, but the vast majority of methane is returned as fuel within the plant or another plant at the same petrochemical site, and thus would produce CO₂ emissions only when combusted.

Response: Please see Section III.X3 of the preamble for the response to this comment.

Commenter Name: See Table 1

Commenter Affiliation:

Document Control Number: EPA-HQ-OAR-2008-0508-0423.2

Comment Excerpt Number: 115

Comment: Ethylene plants should be removed from the Petrochemical Production source category, subpart X, as the vast majority of ethylene plant GHG emissions are from combustion and could be captured in subpart C. As an alternative to excluding ethylene units from the subpart X, EPA could add an emission calculation methodology to subpart X which would allow facilities to calculate combustion emissions based on fuel consumption.

Response: Please see Section III.X.3 of the preamble for the response to this comment.

Commenter Name: John R. Evans

Commenter Affiliation: LyondellBasell Industries

Document Control Number: EPA-HQ-OAR-2008-0508-0718.1

Comment Excerpt Number: 9

Comment: Ethylene production should be removed from the definition of petrochemical production source category. Ethylene production facilities do not produce CO₂ emissions as part of the production process, as for example, the ethylene oxide process does. In addition, other sources of CO₂e emissions from ethylene processes such as flaring and wastewater treatment are typically much less than 1% of total CO₂e emissions. This is recognized by EPA as stated in the technical support document for the petrochemical production sector, page 5, "All of the GHG emissions associated with the ethylene process are from combustion units." GHG emissions from the ethylene combustion sources would be estimated according to the requirements specified in subpart C of the proposed rule even if ethylene was not included in the petrochemical production source category. Ethylene product facilities would all still be captured by other reporting thresholds in section 98.2. This would be true even if the CO₂e reporting threshold was raised from 25,000 to 100,000 tonnes. Inclusion of ethylene in the petrochemical production source category only provides confusion to the rule requirements. As indicated above, nearly all the GHG emissions come from combustion sources that would be reported under subpart C whether or not ethylene was included in the petrochemical source category definition. In addition, the option of using a mass balance approach to determine CO₂e emissions from an ethylene unit makes no sense. Ethylene production units have no normal process vents and CO₂ is not produced in the ethylene production process. This makes the mass balance approach irrelevant and confusing. It is therefore recommended that ethylene production be removed from the definition of the petrochemical production source category.

Response: Please see Section III.X.3 of the preamble for the response to this comment.

Commenter Name: Jeffry C. Muffat

Commenter Affiliation: 3M Company

Document Control Number: EPA-HQ-OAR-2008-0508-0793.1

Comment Excerpt Number: 23

Comment: Section 98.240 of Subpart X, applies to facilities that produce "acrylonitrile, carbon black, ethylene, ethylene dichloride, ethylene oxide, or methanol as an intended product". Certain manufacturing operations will produce methanol as a process by-product. For instance, certain polyester manufacturing operations will produce by-product methanol during the manufacture of polyester resin. Applicability language in many other environmental regulations have addressed this type of issue as a part of a "primary product" determination. The applicability language should clearly state that the Subpart X source category only includes those facilities (or processes) that produce these materials as primary products.

Response: Polyester manufacturing processes that produce methanol as a byproduct are not part of the petrochemical production source category. Any other processes that produce methanol as a byproduct are also not part of the source category. Under the proposed rule, our intent was that such processes would be excluded because they do not produce the petrochemical as an "intended product". Based on the comment, it appears that this approach is ambiguous. To clarify our intent, we restructured the applicability section of subpart X in the final rule (i.e., section 98.240) to specify that all processes that produce a petrochemical are subject unless they meet any of several specified criteria for exclusion from the petrochemical production source category. One of the exclusions is for "a process that produces a petrochemical as a byproduct". We made this change because "byproduct" (i.e., a chemical that is produced coincidentally during the production of another chemical) is a more commonly understood and accepted term

than “intended product”. With respect to basing applicability of subpart X on the production of a petrochemical as a “primary product,” please see Section III.X.3 of the preamble.

Commenter Name: See Table 1

Commenter Affiliation:

Document Control Number: EPA-HQ-OAR-2008-0508-0423.2

Comment Excerpt Number: 15

Comment: In §98.240, the Petrochemical Product (Subpart X) applies to facilities that produce “acrylonitrile, carbon black, ethylene, ethylene dichloride, ethylene oxide, or methanol as an intended product.” Certain manufacturing operations will produce methanol as a process by-product. For instance, certain polyester manufacturing operations will produce by-product methanol during the manufacture of polyester resin. Applicability language in many other environmental regulations have addressed this type of issue as a part of “primary product” determinations. The applicability language should clearly state that Subpart X source category only includes those facilities (or processes) that produce these materials as primary products.

Response: Please see the response to comment EPA-HQ-OAR-2008-0508-0793.1, excerpt number 23.

Commenter Name: Gregory J. Bocchi

Commenter Affiliation: Vinyl Institute (VI)

Document Control Number: EPA-HQ-OAR-2008-0508-1030.1

Comment Excerpt Number: 1

Comment: In particular, VI requests confirmation that a facility producing EDC as part of an integrated process to manufacture VCM would not qualify as a covered petrochemical production source under the NPRM. As proposed, the NPRM would require owners and operators of certain facilities to begin collecting data on GHG emissions beginning January 1, 2010. The first emission report would be due to EPA by March 31, 2011, and annually thereafter for an as yet undetermined period of time. The rule would apply to any facility that in 2010 contained certain designated source categories, including "petrochemical production" facilities. Although the "petrochemical industry" consists of numerous processes that use fossil fuel or petroleum refinery products as feedstocks, the source category is defined by the proposed rule to apply to: "...any facility that produces acrylonitrile, carbon black, ethylene, ethylene dichloride, ethylene oxide, or methanol as an intended product, except as specified in paragraph (b) of this section. (b) An integrated process is part of the petrochemical source category only if the petrochemical is the primary product of the integrated process." According to EPA, the NPRM focuses on the six processes, including EDC production, because the production of GHGs from these processes has been recognized by the Intergovernmental Panel on Climate Change ("IPCC") to be significant when compared to other petrochemical processes. Given the short amount of time provided by the Agency to review the NPRM and its voluminous technical background information, VI can take no position on whether EPA's reliance on the IPCC's finding is warranted or supportable. We note, however, that in calculating emission factors for carbon dioxide and other GHG emissions for EDC production, the IPCC stated that: "Sources of uncertainty for ethylene dichloride include the difficulty in determining the specific process utilized for the ethylene dichloride production and in determining activity data for the consumption of ethylene feedstock in the production process. If only activity data for ethylene

dichloride production are available, the emission calculation may be conducted using the default [balanced] process product yield factor and default emission factor for the process. However, considering the variability in emission factors and yield factors for the oxychlorination process, direct oxidation process, and balanced process, the unavailability of specific ethylene feedstock consumption data by process would introduce significant uncertainty into the emissions calculations." [Footnote: Lanza, R., Martinsen, T., Karim, A., Mohammad, W., and Santos, M. Chemical Industry Emissions, in 2006 IPCC Guidelines for National Greenhouse Gas Inventories, vol. 3, § 3.9.3, at 3.85 (H.S. Eggleston et al. eds., Institute for Global Environmental Strategies 2006), available <http://www.ipcc-nggip.iges.or.jp/public/2006gl/vol3.html>.] We also note the IPCC indicated uncertainty levels of -50% to +20% for the Tier I default approach for emission factors for EDC/VCM plants. Similarly, EPA's Technical Support Document estimated the uncertainty of its Option 2, the Carbon Mass Balance approach, at 58%. Clearly, neither of these methods is considered very accurate. The EPA proposes to define an "integrated process" as one that "produces a petrochemical as well as one or more other chemicals that are part of other source categories under this part." By operation of proposed 40 C.F.R. § 98.240(b) cited above, however, an integrated process manufacturing EDC would be part of the petrochemical source category only if EDC is the primary product. The rule would define a "primary product" as "the product of a process that is produced in greater mass quantity than any other product of the process." EPA has previously defined "primary product" in a manner that excludes EDC manufactured in an integrated VCM production unit from being considered the "primary product." The National Emission Standards for Organic Hazardous Air Pollutants ("NESHAP") from the Synthetic Organic Chemical Manufacturing Industry, commonly referred to as the hazardous organic NESHAP or HON, defines a chemical manufacturing process unit to mean:[Footnote: 59 Fed. Reg. 19,454 (Apr. 22, 1994) (codified at 40 C.F.R. Part 63, subpart F).] " ... the equipment assembled and connected by pipes or ducts to process raw materials and to manufacture an intended product. A chemical manufacturing process unit consists of more than one unit operation. A chemical manufacturing process unit is identified by its primary product... Product means a compound or chemical which is manufactured as the intended product of the chemical manufacturing process unit. By-products, isolated intermediates, impurities, wastes, and trace contaminants are not considered products." [Footnote: 40 C.F.R. § 63.101(b).] The HON prescribes several procedures for determining the primary product of a chemical manufacturing process unit. Of particular relevance here: "If a chemical manufacturing process unit produces more than one intended chemical product, the product with the greatest annual design capacity on a mass basis determines the primary product of the process" [Footnote: 40 C.F.R. § 63.100(d)(1).] Thus, a facility that only produces EDC would be a HON affected "chemical manufacturing process unit" whose intended product is EDC. Therefore, the primary product of a "stand alone" EDC facility would be EDC. The final EDC product from such facilities is distributed to various customers for use in the production of VCM, as an intermediate in the manufacture of trichloroethane and fluorocarbons, or possibly for use in solvent applications. Conversely, a facility that produces EDC, which is then cracked within the facility to manufacture VCM, would be a HON affected "chemical manufacturing process unit" that is identified by its primary product of VCM. VI requests confirmation that the primary product definition under proposed section 40 C.F.R. § 98.240(b) would exclude VCM production units from the Petrochemical Production Sector of the GHG reporting rule. This is consistent with the EDC production feedstock-product flow diagram (Figure 3.12) in Annex 3.9A of the above referenced IPCC Report. If it is EPA's intent to include such units, VI strongly urges EPA to consider a basis other than "primary product" for such inclusion in order to avoid confusion caused by the use of identical terminology for dissimilar regulatory schemes.

Response: Please see Section III.X.3 of the preamble for the response to this comment.

Commenter Name: Stephen B. Kemp

Commenter Affiliation: Occidental Chemical Corporation (OCC)

Document Control Number: EPA-HQ-OAR-2008-0508-0644.1

Comment Excerpt Number: 9

Comment: The proposed rules found at Subpart X – Petrochemical Production define the petrochemical source category as follows: § 98.240 Definition of the source category. (a) The petrochemical production source category consists of any facility that produces acrylonitrile, carbon black, ethylene, ethylene dichloride, ethylene oxide, or methanol as an intended product, except as specified in paragraph (b) of this section. (b) An integrated process is part of the petrochemical source category only if the petrochemical is the primary product of the integrated process. The proposed rules list ethylene dichloride (EDC) production as a petrochemical. OCC has manufactured and continues to manufacture EDC both as an end product as well as an intermediate for over twenty-five years and is a major manufacturer of this chemical substance. Thus OCC fully understands this manufacturing process. OCC's EDC manufacturing operations are located in Houston, Texas; Corpus Christi, Texas; Geismar, Louisiana; and, Convent, Louisiana. Petrochemicals have been traditionally defined as any of the chemicals derived from petroleum or natural gas. The definition of petrochemicals may include the range of aliphatic, aromatic, and naphthenic organic chemicals, as well as carbon black and such inorganic materials as sulfur and ammonia. Petrochemicals are made or recovered from the petroleum fractions, but the bulk of petrochemical products are formed from the lighter (C1–C4) hydrocarbon gases as raw materials. These materials generally occur in natural gas, but they are also recovered from the gas streams produced from petroleum refinery operations. Consistent with the aforementioned, on page 16536 of the preamble to the proposed rule, the following is stated: "X. Petrochemical Production 1. Definition of the Source Category The petrochemical industry consists of numerous processes that use fossil fuel or petroleum refinery products as feedstocks." It is important to note that EDC is manufactured by reacting ethylene and chlorine (or hydrogen chloride) and as such is not derived from petroleum, natural gas or other fossil fuel-based feedstock. Ethylene is supplied via pipeline from off-site manufacturing locations; chlorine (or hydrogen chloride) is generally produced on-site. These chemical substances are combined in a reactor, where in the presence of a catalyst, EDC is formed. Given that EDC is not manufactured by using crude oil, naphtha, natural gas condensate, methane or other petroleum, natural gas or other fossil fuel-based feedstock, we dispute EPA's decision to categorize EDC as a petrochemical. On page 16536 of the preamble EPA stated the following: "...88 facilities operating petrochemical processes in the U.S., and 9 of these operate either two or three types of petrochemical processes (e.g., ethylene and ethylene oxide). We estimate petrochemical production accounts for approximately 55 million metric tons CO₂e." Carbon dioxide, methane, nitrous oxide, sulfur hexafluoride and the other greenhouse gases listed in the proposal are not used in the manufacture of EDC, and only a trace amount of carbon dioxide is generated during the EDC manufacturing process. GHG emission sources are from boilers and thermal oxidizers used for vent controls. [footnote: OCC EDC facilities are not equipped with flares.] Like many other processes, GHG emissions from these sources would be adequately covered via the requirements listed in proposal Subpart C - General Stationary Fuel Combustion Sources. Further, steam is provided to the process via boilers (the emissions for which are covered under proposed Subpart C - General Stationary Fuel Combustion Sources), and thus GHG emissions from EDC facilities are virtually no different than any other chemical manufacturing process. OCC estimates that annual GHG emissions from an OCC site that manufactures both EDC and chlorine to be about 60,000 Metric Tons of CO₂e. The majority of these emissions are associated

with the combustion of natural gas and vent gases in combustion devices, and thus would be reported under proposed Subpart C. We estimated that about one-third of these emissions are (20,000 Metric Tons CO₂e) are associated with EDC manufacture at this facility. Based on information contained in the proposed preamble, this facility would account for only about 0.04 percent of the proposed source category emissions. In summary, EDC is not manufactured using a fossil fuel-based feedstock, the manufacturing process does not utilize any listed GHG in the manufacturing process, and the GHG emissions from such processes are small and would be reported elsewhere under the proposed rule. Accordingly, we respectfully request that EPA remove ethylene dichloride manufacturing from the petrochemical source category. Specifically, the language found at proposed §98.240 should be read as follows: § 98.240 Definition of the source category. (a) The petrochemical production source category consists of any facility that produces acrylonitrile, carbon black, ethylene, ethylene oxide, or methanol as an intended product, except as specified in paragraph (b) of this section.

Response: Please see Section III.X.3 of the preamble for the response to this comment.

Commenter Name: Lloyd Stone

Commenter Affiliation: Westlake Chemical Corporation

Document Control Number: EPA-HQ-OAR-2008-0508-0442.1

Comment Excerpt Number: 14

Comment: The applicability statement in subsection 98.240(b) is confusing given the definition of “integrated process” in 98.6. Does EPA intend ethylene units and ethylene dichloride units to be exempt from reporting if their product streams are later used as feedstocks to make vinyl chloride monomer/polyvinylchloride resin or polyethylene downstream in the plant?

Response: Please see Section III.X.3 of the preamble for the response to this comment.

Commenter Name: David P. DiBoyan

Commenter Affiliation: International Carbon Black Association (ICBA)

Document Control Number: EPA-HQ-OAR-2008-0508-0678.1

Comment Excerpt Number: 6

Comment: In section 98.6, a definition for "carbon black oil" is provided. The ICBA suggests that the term "carbon black oil" be revised to read "carbon black feedstock" so the terminology is consistent with that used throughout the industry.

Response: The term “carbon black oil” was used in a draft of the proposed rule. When the term was subsequently removed before proposal, we neglected to remove the definition at the same time. Therefore, the term has been deleted from the final rule.

Commenter Name: Lloyd Stone

Commenter Affiliation: Westlake Chemical Corporation

Document Control Number: EPA-HQ-OAR-2008-0508-0442.1

Comment Excerpt Number: 13

Comment: In regards to EPA’s request for public comment on fugitive emissions, Westlake believes that these should not be addressed by the rule due to their negligible impact on CO₂e emissions. This position is based on the fact that these fugitive emissions are non-methane, non-carbon dioxide based emissions from ethylene processes.

Response: We appreciate the commenter’s response to our request for comments regarding fugitive emissions. We have not received any comments with a rationale for estimating fugitive GHG emissions from petrochemical process units. Therefore, the final rule, like the proposed rule, does not explicitly require separate estimates of fugitive and stack emissions from such process units. Note, however, that when using the mass balance option, the difference between the measured carbon input and the measured carbon output represents all stack and fugitive losses of carbon, and all of this carbon is assumed to be in the form of CO₂. Therefore, any fugitive CO₂ emissions are estimated in the total CO₂ emissions for the process, and any carbon in fugitive hydrocarbon emissions, like CH₄ or ethylene, are also assumed to be emitted as CO₂.

2. REPORTING THRESHOLD

Commenter Name: Matthew Frank

Commenter Affiliation: Wisconsin Department of Natural Resources

Document Control Number: EPA-HQ-OAR-2008-0508-1062.1

Comment Excerpt Number: 14

Comment: This subpart does not identify a reporting threshold indicating any emissions from petrochemical plants would need to report. Is this correct?

Response: As noted in Subpart A of the final rule, the petrochemical production source category is in the “all in” category, which means that all facilities with a petrochemical process must report, regardless of their production levels or other operating characteristics. The rationale for this requirement was provided in the preamble to the proposed rule. However, in response to comments, section 98.240 of the final rule explicitly identifies certain processes that are not part of the source category.

3. GHGS TO REPORT

Commenter Name: See Table 3

Commenter Affiliation:

Document Control Number: EPA-HQ-OAR-2008-0508-0679.1

Comment Excerpt Number: 172

Comment: §98.242. EPA’s rule focuses on CO₂ emissions from petrochemical production, with no mention of CH₄ or N₂O emission. This is contrary to the EPA Inventory of Greenhouse Gas Emissions and Sinks which estimates CH₄ emission from carbon black, ethylene, ethylene dichloride, and methanol; and N₂O emissions from nitric acid and adipic acid production. [The Compendium cites emission factors for CH₄ and N₂O from the EPA national inventory.]

Response: Of the four petrochemical processes cited by the commenter, ethylene production generates more CH₄ emissions than the other 3 processes combined, especially when using the 2006 IPCC Tier 1 factors rather than the 1996 factors that were used to estimate emissions for the EPA Inventory. As discussed in Section III.X.3 of the preamble, the final rule allows ethylene manufacturers to monitor and report in accordance with the methodology for stationary combustion sources in Subpart C as an alternative to the mass balance methodology or the CEMS option. We expect that most ethylene manufacturers will elect to comply using the stationary combustion methodology because this option was requested by a number of commenters. As a result, these ethylene manufacturers will be estimating CH₄ and N₂O emissions as well as CO₂ emissions.

The mass balance option in the final rule, like the proposed rule, does not require petrochemical producers to calculate CH₄ and N₂O process emissions for several reasons. First, based on the IPCC Tier 1 emission factors, the contribution of CH₄ to the CO_{2e} from petrochemical processes other than ethylene is small. For example, the contribution is much less than 1 percent of the total for EDC and carbon black processes and about 2 percent for methanol processes. Second, the mass balance approach assumes that the difference between input and output measured carbon is all lost as CO₂. This means any CH₄ emissions are assumed to be CO₂, which also means a separate estimate of CH₄ emissions using factors like the IPCC Tier 1 factors would partially double-count emissions that are calculated using the mass balance. Third, part of the CH₄ emissions accounted for by the IPCC Tier 1 factors (and in the EPA Inventory) is for CH₄ derived from supplemental fuel. For example, all of the CH₄ emissions from EDC processes are from uncombusted supplemental fuel. Section 98.242(b) of the final rule clarifies that these emissions (as well as the CO₂ and N₂O emissions from supplemental fuel combustion in stationary combustion units) are to be calculated and reported in accordance with Subpart C. Finally, the mass balance approach in the final rule is consistent with the Tier 2 IPCC methodology, which does not estimate CH₄ emissions.

Nitric acid and adipic acid are not in the petrochemical production source category. They are, however, covered in Subparts V and E of the final rule, respectively.

4. SELECTION OF PROPOSED GHG EMISSIONS CALCULATION AND MONITORING METHODS

Commenter Name: See Table 3

Commenter Affiliation:

Document Control Number: EPA-HQ-OAR-2008-0508-0679.1

Comment Excerpt Number: 174

Comment: “Section 98.243 requires process-based GHG emissions to be determined based on either a continuous emission monitoring system (CEM) or by conducting a weekly mass balance for each petrochemical process unit. As discussed in the Technical Support Document of the Petrochemical Production Sector, “All of the emissions associated with the ethylene process are from combustion units.” This statement is consistent with EPA's determination during the Ethylene MACT rulemaking that ethylene plants do not have continuous process vents. Therefore, the emissions quantification methodology provided in §98.243 is not appropriate for ethylene production plants. Alternatively, subpart C would provide the appropriate methodologies for estimating GHG emissions from ethylene production plants. The most

accurate means of determining ethylene unit GHG emissions is to base the determination on fuel combustion, which is the methodology used currently by most ethylene units. These units typically do not have CEMS, and the proposed alternative, a weekly mass balance requirement, is onerous and most likely would be less accurate than a fuel combustion methodology.

Response: Please see Section III.X.3 of the preamble for the response to this comment.

Commenter Name: See Table 1

Commenter Affiliation:

Document Control Number: EPA-HQ-OAR-2008-0508-0423.2

Comment Excerpt Number: 117

Comment: Section 98.243 requires process-based GHG emissions to be determined based on either a continuous emission monitoring system or by conducting a weekly mass balance for each process unit. These proposed methods are not appropriate for ethylene units which, as determined by EPA in the Ethylene NESHAP rulemaking, do not have continuous process vents. These units typically do not have CEMS, and the proposed alternative, a weekly mass balance requirement, is an onerous undertaking considering the relatively small amount of GHG emissions. We offer the following example to illustrate the concern: For every 100,000 pounds of ethylene produced, there could be as much as 300,000 pounds of feed coming from 3-4 different sources (e.g. gas oils, kerosenes, ethane, etc.). In a complex olefins plant, the same 300,000 pounds of feed would be converted into 300,000 pounds of products divided among 10-12 different product draws ranging from heavy gas oil to hydrogen. The amount of CO₂ produced in the cracking process will be approximately 50 pounds. Compare this with the CO₂ produced from fuel combustion. The amount of fuel gas burned to produce the same 100,000 pounds of ethylene would be approximately 0.9-1.0 billion BTUs, or about 50 tons of CO₂ from combustion. It seems impractical to do a detailed material balance on 12-16 streams comprising some 300,000 pounds of feed and 300,000 pounds of products and expect to find 50 lb of CO₂ by difference. This is a huge amount of effort to account for less than 0.05% of the CO₂ produced in the process. Further, for ethylene process units co-located with a petroleum refinery or other chemical plant units, any off-gas is sent to the fuel gas system where it is mixed with other process gases from non-ethylene units in a fuel gas blend drum and then distributed to combustion units throughout the refinery and/or chemical plant. As an alternative to the CEMS or mass balance option, subpart C would provide the appropriate methodologies for estimating GHG emissions from ethylene plants since, as EPA notes in its Technical Support Document for the Petrochemical Product Sector, "All of the GHG emissions associated with the ethylene process are from combustion units." The most accurate means of determining ethylene unit GHG emissions is to base the determination on fuel combustion, which is the methodology used currently by most ethylene units.

Response: Please see Section III.X.3 of the preamble for the response to this comment.

Commenter Name: See Table 1

Commenter Affiliation:

Document Control Number: EPA-HQ-OAR-2008-0508-0423.2

Comment Excerpt Number: 119

Comment: Section 98.243(a)(1) references 98.253(b)(1)(i – iii) and (b)(2) for determining emissions from flares. EPA’s proposed 98.253(b)(1)(ii and iii) should also acknowledge that some facilities have an on-line GC capable of measuring the composition of the flared gas. Information from an on-line GC should also be allowed to be used in the carbon content and higher heating value determinations for routine vents and also as an option for determining these values during times of start-up, shutdown, and malfunction vent scenarios.

Response: Section 98.254(d) in the final subpart Y specifies test methods that may be used to determine the flare gas composition. The list includes GC methods. In addition, section 98.253(b) of the final rule has been changed to use the term “gas composition” monitor to clarify that a GC (either on-line or in a laboratory) may be used when determining carbon content.

Commenter Name: See Table 1

Commenter Affiliation:

Document Control Number: EPA-HQ-OAR-2008-0508-0423.2

Comment Excerpt Number: 118

Comment: EPA proposes the following in 98.243(a)(1)(ii) : “If you elect to install CEMS to comply with this subpart, you must route all process vent emissions to one or more stacks and use a CEMS on each stack (except flare stacks) to measure CO₂ emissions.” It may not be possible to connect a single CEMS to several process vent sources since it depends on many factors, including the capacity of the CEMS to accept several sources and the physical location of the various sources relative to the CEMS. A facility should have the option to install a CEMS on one or more sources without being required to have a CEMS on all sources associated with a petrochemical production process. For example, a company may want to use an existing CEMS to measure CO₂ emissions from one emission point in an ethylene oxide/glycol manufacturing plant, but also to have the flexibility to use the combustion equations in Subpart C or the mass balance approach for other smaller points that are also present in the process. These smaller emission points include sources like start-up heaters and steam jet exhausts from distillation columns operating under vacuum. In this case, it would not be feasible to use the same CEMS or install multiple CEMS to measure CO₂ emissions from these smaller sources. The owner/operator should have the flexibility to use a CEMS on larger CO₂ emission sources, and to use other GHG emission determination methodologies on other sources within the same petrochemical production process.

Response: Please see Section III.X.3 of the preamble for the response to this comment.

Commenter Name: Robert Rouse

Commenter Affiliation: The Dow Chemical Company

Document Control Number: EPA-HQ-OAR-2008-0508-0533.1

Comment Excerpt Number: 31

Comment: EPA’s Proposed CEMS Requirements are Overly Restrictive for Petrochemical Production Processes and Need to be Made More Flexible. In 98.243 (a)(1)(ii), EPA proposes the following: “If you elect to install CEMS to comply with this subpart, you must route all process vent emissions to one or more stacks and use a CEMS on each stack (except flare stacks) to measure CO₂ emissions.” It may not be possible to connect a single CEMS to several process vent sources, depending on many factors including the capacity of the CEMS to accept several

sources and the physical location of the various sources relative to the CEMS. A facility should have the option to install a CEMS on one or more sources without being required to have a CEMS on all sources associated with a petrochemical production process. For example, a facility may want to use an existing CEMS to measure CO₂ emissions from one emission point in an ethylene oxide/glycol manufacturing plant, but also have the flexibility to use the combustion equations in Subpart C or the mass balance approach for other smaller points that are also present in the process. These smaller emission points include sources like start-up heaters and steam jet exhausts from distillation columns operating under vacuum. In this case, it would not be feasible to use the same CEMS or install multiple CEMS to measure CO₂ emissions from these smaller sources. The owner/operator should have the flexibility to use a CEMS on larger CO₂ emission sources and to use other GHG emission determination methodologies on other sources within the same petrochemical production process. EPA's Flare Provisions Should Also Account for Cases Where an On-Line Analyzer is Available on Flare Header. Section 98.243(a)(1) references 98.253(b)(1)(i – iii) and (b)(2) for determining emissions from flares. EPA's proposed 98.253(b)(1)(ii and iii) should also acknowledge that some facilities have an on-line gas chromatographs (GC) capable of measuring the composition of the flared gas. Information from an on-line GC should also be allowed to be used in the carbon content and higher heating value determinations for routine vents and also as an option for determining these values during times of start-up, shutdown, and malfunction vent scenarios.

Response: For the response to this comment, please see the response to comment EPA-HQ-OAR-2008-0508-0423.2, excerpt number 119, and Section III.X.3 of the preamble.

Commenter Name: David P. DiBoyan

Commenter Affiliation: International Carbon Black Association (ICBA)

Document Control Number: EPA-HQ-OAR-2008-0508-0678.1

Comment Excerpt Number: 3

Comment: Subpart X - 98.3 requires reporting of "emissions and other data for individual units, processes, activities, and operations... ICBA member companies use a fundamentally sound and validated mass balance methodology to calculate site-wide emissions. This methodology is currently being used to report SO₂ emissions for State Title V permits. Carbon black facilities are complex and dynamic, due primarily to customer demands and variation, so collecting mass balance calculations for individual units, processes, operations or activities is not practical and the ICBA believes the data on individual units or process emissions is unnecessary to achieve the purposes of this rule.

Response: Having measurement information on a unit basis will be valuable in characterizing processes for future policy analyses, such as flexibility for EPA to offer industry assistance programs. Although carbon black facilities make numerous different grades and varieties of products, even the facilities with the largest production capacity have only a small number of process units (up to 8 at one facility). Each unit also generally is dedicated to either industrial grade products or rubber grade products. Within each process unit, knowledge of the quantity and composition of feedstocks is needed to properly operate the process, and knowledge of the quantity and composition of each product is needed to meet customer requirements. Therefore, we have concluded that the mass balance option can be implemented on a process unit basis at carbon black facilities, and this option is retained in the final rule.

Commenter Name: Lloyd Stone
Commenter Affiliation: Westlake Chemical Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0442.1
Comment Excerpt Number: 15

Comment: 98.243(a)(1)(i):The CEMS option gives you the ability to measure CO₂, etc. on the outlet of an emission point. We would like to see an option for using process based gas chromatograph, prior to incineration (or control) to calculate the concentration of CO₂, and to determine the concentration of other miscellaneous combustible species (that will ultimately generate CO₂ after combustion).

Response: The approach suggested by the commenter is essentially the Tier 3 methodology in subpart C. Thus, it is allowed in the final rule for ethylene manufacturers who elect to comply with the new option to implement the subpart C methodology (see the preamble for the response on ethylene inclusion in the petrochemical production source category for a discussion of this option). It is also allowed as an option for calculating emissions from flares (i.e., the referenced methodology in subpart Y). For other petrochemical processes, the suggested approach also theoretically could be used as an alternative to CEMS for some or all of the affected vents and stationary combustion source stacks under the CEMS option. (Note that for vents that are not routed to combustion sources, only CO₂ would need to be measured, which would be equivalent to measuring CO₂ with a CEMS.) However, we have not included the suggested option in the final rule because we are not aware of any facilities that have such equipment in place, and we think the impacts to install and operate such equipment would be significantly greater than the impacts for the mass balance. We will consider adding the suggested option in the future if the industry continues to express an interest in it.

5. DETAILED GHG EMISSION CALCULATION PROCEDURES/EQUATIONS IN THE RULE

Commenter Name: See Table 3
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0679.1
Comment Excerpt Number: 173

Comment: §98.243(a)(2). Two sets of brackets should be added to Eq. X-2 to identify the proper use of the summations. Two sets of brackets should also be added to Eq. X-3 to identify the proper use of the summations.

Response: The commenter is correct. The suggested changes have been made in the final rule.

Commenter Name: See Table 1
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0423.2
Comment Excerpt Number: 124

Comment: EPA states on page 16537 of the preamble that organic liquid wastes that are collected for shipment offsite would also be considered an output in the carbon balance. This

concept is not clear in the equations contained in the proposed rule and should be clarified. In addition, we believe that the owner/operator should have the option to improve the overall mass balance by subtracting organic materials that are discharged from the process to a waste water sewer or collection system, accounting for materials vented to emission control devices, and to account for air emissions of organic materials. Therefore, the mass balance equation could look like this: $C_x = \text{Carbon content of feedstocks in} - \text{Carbon content of all products out} - \text{Carbon content of liquid wastes} - \text{Carbon content of organics discharged to sewer} - \text{Carbon content of organics vented to an emission control device} - \text{Carbon content of organics emitted to atmosphere}$. Note: The last three variables (discharges to sewer, vents to control devices, and vents to atmosphere) should be optional for those companies desiring to provide a higher quality carbon balance for their respective operations. Companies should also be allowed to use process knowledge and engineering calculations to determine these last four variables. As stated in our comments above, a monthly accounting/material balance would allow for sufficient determination of all of the variables.

Response: Upon review of this comment, we have made two changes in the final rule to clarify that liquid organic wastes are to be included in the mass balance. First, the term C_1 in Equation X-2 is now defined as “[a]nnual net contribution to estimated emissions from carbon in liquid materials, including liquid organic wastes (kg/yr)”. Second, we have defined the term “product” in section 98.248 to mean, in “each of the following carbon-containing outputs from a process: the petrochemical, recovered byproducts, and liquid organic wastes that are not incinerated onsite...”. The final rule, like the proposed rule, requires measurements rather than estimates of the liquid wastes because these are collected materials that are amenable to measurement without undue burden.

Theoretically, accounting for all hydrocarbon losses would improve the estimate of CO_2 emissions. Vent streams with the most significant hydrocarbon content, however, are routed to combustion devices such as thermal incinerators and flares; GHG emissions from these control devices are accounted for in the mass balance option. The carbon lost in hydrocarbons discharged to wastewater and in vents to the atmosphere (or fugitive losses) are expected to be very small relative to the quantity of carbon contained in CO_2 generated in the process and/or from the combustion of process off-gas. We are not requiring estimates of these losses because we tried to strike a balance between the level of effort and the accuracy of the results. However, because information about the magnitude of such losses may prove useful in future policy decisions, we have specified in the final rule that a reporter may elect to estimate and report carbon content in wastewater and process losses (i.e., fugitives and vents that are not routed to a combustion device) in addition to the otherwise required information. The carbon content in these losses may be either estimated using engineering analyses or measured using methods like those required for feedstocks and products. Note, however, that the results are not to be included in the mass balance calculation of CO_2 emissions. Also please see Section III.X.3 of the preamble for additional response to this comment.

Commenter Name: See Table 1

Commenter Affiliation:

Document Control Number: EPA-HQ-OAR-2008-0508-0423.2

Comment Excerpt Number: 123

Comment: Molar Volume Conversion Factor for Gas Streams – EPA states that this is 849.5 scf per kg-mole at standard conditions. EPA’s proposed definition of Standard Conditions in §98.6

states that standard temperature is 60° F. Using the ideal gas law, this would yield the following for molar volume: $(10.73)(520)/(14.696) = 379.7$ scf per lb-mole $\times 2.2 = 835.3$ scf per kg-mole. It appears that EPA may have used 68° F as standard temperature in the calculation of molar volume. Therefore, EPA should decide on the correct standard temperature to use and align the definition of Standard Conditions with the calculation of molar volume for gases.

Response: For the final rule, the specified temperature in the definition of the term “standard conditions” in section 98.6 is 68 degrees Fahrenheit. Thus, the molar volume conversion factor of 849.5 scf per kg-mole in Equation X-1 is now correct.

Commenter Name: See Table 1

Commenter Affiliation:

Document Control Number: EPA-HQ-OAR-2008-0508-0423.2

Comment Excerpt Number: 122

Comment: Equations Eq. X-1 – 3 pose a significant problem in cases where the raw materials and products are different states of matter. For example, one ethylene oxide manufacturing process uses ethylene gas as a raw material and the products are ethylene oxide (light liquid) and ethylene glycol, diethylene glycol, and triethylene glycols (heavy liquids). The equations must be made general to reflect these types of situations.

Response: Upon review of the comment, EPA has clarified the requirements. We have included introductory paragraphs in the final rule prior to each equation explaining how to use them. If feedstock and products are different states of matter, the reporter must use two (or even all three) equations. In the example cited by the commenter, the feedstock portion of Equation X-1 would be used to estimate the carbon in the gaseous feedstock, and the product portion of equation X-2 would be used to estimate the carbon in the liquid products. The result from Equation X-1 would be positive, and the result from Equation X-2 would be negative. These values would be entered in Equation X-4 such that the difference represents the CO₂ emissions.

Commenter Name: See Table 1

Commenter Affiliation:

Document Control Number: EPA-HQ-OAR-2008-0508-0423.2

Comment Excerpt Number: 121

Comment: In 98.243(a)(2)(iii – iv), EPA should allow an option of opting out of weekly sampling if statistical analysis of samples shows that a lesser sampling frequency is justified statistically. In addition, EPA should revise the reduced sampling criteria to 99% with the logic being that up to 1% of an impurity present will not significantly alter the carbon balance for a large-scale petrochemical process. In addition, in some cases, defaulting to 100% of the feedstock or product may also result in an over-estimate of the carbon content depending on the specific material so EPA should not be so stringent with a 99.5% speciation criteria.

Response: With respect to monitoring frequency, please see the discussion in Section III.X.3 of the preamble. We have not included an option to vary the length of the monitoring periods based on the results of statistical analyses because of revisions made to the monitoring frequency and because the commenter did not provide a detailed description of how such a statistical analysis might work. We also have not lowered the 99.5 percent criterion because it would decrease the

accuracy of the mass balance (i.e., it would exacerbate the overestimate of carbon in the affected stream as noted by the commenter). Furthermore, the intent of the option was to provide a simple option that could potentially minimize impacts in situations where an estimate would give essentially the same results as more costly sampling and analysis. This equivalence occurs only if the feedstock or product is essentially a pure material.

Commenter Name: Lloyd Stone

Commenter Affiliation: Westlake Chemical Corporation

Document Control Number: EPA-HQ-OAR-2008-0508-0442.1

Comment Excerpt Number: 17

Comment: 98.243(a)(2)(iii) and (iv): These allow the option to consider a stream 100% if weekly average concentrations are always shown to be greater than 99.5%. What about streams that are consistent, but may be less than pure. Westlake encourages EPA to allow a method to use an average or upper control limit using a 90% confidence interval, or the like.

Response: Please see the response to comment EPA-HQ-OAR-2008-0508-0423.2, excerpt number 121.

Commenter Name: See Table 1

Commenter Affiliation:

Document Control Number: EPA-HQ-OAR-2008-0508-0423.2

Comment Excerpt Number: 120

Comment: EPA should revise the requirements for the mass balance approach in §98.243(a)(2) such that the emissions of CO₂ from each process unit are estimated each calendar month rather than each calendar week. Monthly accounting aligns much better with existing industry accounting practices and should be in sufficient detail to provide a high quality estimate for the annual GHG reporting rule. Such an approach would reduce the burden on the source owner/operator, align with internal monthly accounting practices, and provide 12 high quality estimates that can be used for annual GHG reporting.

Response: Please see Section III.X.3 of the preamble for the response to this comment.

Commenter Name: David P. DiBoyan

Commenter Affiliation: International Carbon Black Association (ICBA)

Document Control Number: EPA-HQ-OAR-2008-0508-0678.1

Comment Excerpt Number: 2

Comment: Subpart X – 98.243(a)(2) requires that a weekly mass balance calculation be performed for each unit. The ICBA recommends that the proposed requirement be amended to require a monthly mass balance calculation for each facility. The emissions from a carbon black manufacturing facility do not vary significantly from week-to-week, so a monthly mass balance calculation is more than adequate to track GHG emissions. The collection of data on a more frequent basis is unnecessary and onerous.

Response: Please see Section III.X.3 of the preamble for the response to this comment.

Commenter Name: Robert Rouse

Commenter Affiliation: The Dow Chemical Company

Document Control Number: EPA-HQ-OAR-2008-0508-0533.1

Comment Excerpt Number: 32

Comment: EPA Should Change the Frequency of Mass Balance Calculations to at Least Monthly vs. Weekly. In 98.243(a)(2), EPA should revise the requirements for the mass balance approach such that the emissions of CO₂ from each process unit will be estimated for each calendar month vs. each calendar week. Monthly accounting aligns much better with existing industry accounting practices and would be in sufficient detail to provide a high quality estimate for the GHG Reporting Rule. Such an approach would reduce the burden on the source owner/operator, align with internal monthly accounting practices, and provide 12 high quality estimates that can be used for annual GHG reporting. EPA Should Revise the Requirements for Weekly Sampling of Feedstocks and Products to Determine the Carbon Content. In 98.243(a)(2)(iii – iv), EPA should allow opting out of weekly sampling if statistical analysis of samples shows that a lesser sampling frequency is statistically justified. In addition, EPA should revise the reduced sampling criteria to 99% with the logic being that up to 1% of an impurity present will not significantly alter the carbon balance for a large-scale petrochemical process. In addition, in some cases, defaulting to 100% of the feedstock or product may also result in an over-estimate of the carbon content depending on the specific material. Therefore, EPA should not be so stringent with a 99.5% speciation criteria. EPA Should Modify Equations Eq. X-1, Eq. X-2 and Eq. X-3 into a Single Equation to Account for Different Physical States of Feedstocks and Products. In 98.243(a)(2), Equations Eq. X-1 – 3 provide a significant problem in cases where the raw materials and products are different states of matter. Equations Eq. X-1, Eq. X-2 and Eq. X-3 assume that if the feedstock is liquid, the product is also liquid, and likewise for gaseous or solid feeds and products. However, for example, one ethylene oxide manufacturing process uses ethylene gas as a raw material, and the products are ethylene oxide (light liquid) and ethylene glycol, diethylene glycol, and triethylene glycols (heavy liquids). The equations in 98.243(a)(2) must be made to reflect these types of situations. Therefore, instead of providing three individual equations, EPA should provide a single equation for all feedstocks and all products. Equation X-1 Molar Volume Conversion Factor for Gas Streams – EPA states that this is 849.5 scf per kg-mole at standard conditions. EPA’s proposed definition of Standard Conditions in 98.6 states that standard temperature is 60° F. Using the ideal gas law, this would yield the following for molar volume: $(10.73)(520)/(14.696) = 379.7$ scf per lb-mole x 2.2 = 835.3 scf per kg-mole. It appears that EPA may have used 68° F as standard temperature in the calculation of molar volume. Therefore, EPA should decide on the correct standard temperature to use and align the definition of Standard Conditions with the calculation of molar volume for gases. This is an issue in other subparts of the proposed rule as well. Optional Inclusion of Wastewater Streams, Vents Routed to Control Devices, and VOC Emissions in the Material Balance Equations. EPA states on Page 16537 of the preamble that organic liquid wastes that are collected for shipment offsite would also be considered an output in the carbon balance. This concept is likely not clear in the equations contained in the proposed rule. In addition, the owner/operator should also have the option to improve the overall mass balance by subtracting organic materials that are discharged from the process to a wastewater sewer or collection system, accounting for materials vented to emission control devices, and to account for air emissions of organic materials. Therefore, the mass balance equation could look like this: $C_x = \text{Carbon content of feedstocks in} - \text{Carbon content of all products out} - \text{Carbon content of liquid wastes} - \text{Carbon content of organics discharged to sewer} - \text{Carbon content of organics vented to}$

an emission control device – Carbon content of organics emitted to atmosphere. Note: The last three variables (discharges to sewer, vents to control devices, and vents to atmosphere) should be optional for those companies desiring to provide a higher quality carbon balance for their respective operations. Companies should also be allowed to use process knowledge and engineering calculations to determine these last four variables. As stated in an earlier comment, a monthly accounting/material balance would allow for sufficient determination of all of the variables.

Response: Please see the responses to comments EPA-HQ-OAR-2008-0508-0423.2, excerpt numbers 120, 121, 122, 123, and 124.

Commenter Name: Lloyd Stone

Commenter Affiliation: Westlake Chemical Corporation

Document Control Number: EPA-HQ-OAR-2008-0508-0442.1

Comment Excerpt Number: 16

Comment: In 98.243(a)(1)(ii), Westlake would like to see flexibility in the regulation to allow "Other" means of calculating the carbon content by way of "Best Engineering Judgment".

Response: Upon review of this comment, we decided not to include an option to calculate carbon content using "best engineering judgment" in the final rule because the commenter has not explained how the carbon content would be calculated using "best engineering judgment". In addition, it is likely that facilities would use different procedures, with different accuracy and uncertainty levels, potentially leading to significantly different results.

6. MONITORING AND QA/QC REQUIREMENTS

Commenter Name: See Table 3

Commenter Affiliation:

Document Control Number: EPA-HQ-OAR-2008-0508-0679.1

Comment Excerpt Number: 176

Comment: §98.244(a)(3). Reporters are required to collect a sample of each feedstock and product for each process unit at least once per week to determine the carbon content. The composition of the feedstock and product do not vary significantly because feedstocks and products must meet strict specifications standards. Specifications for various impurities are in the ppm range and not the percent range. Thus, less frequent sampling is warranted. API requests a provision to allow the reporter to determine a sampling frequency that is consistent with the variability of the stream.

Response: Please see Section III.X.3 of the preamble for the response to this comment.

Commenter Name: See Table 3

Commenter Affiliation:

Document Control Number: EPA-HQ-OAR-2008-0508-0679.1

Comment Excerpt Number: 175

Comment: §98.244(a)(2). Reporters that are using the mass balance methodology are required to measure the volume of each gaseous and liquid feedstock and product continuously using a flow meter. Flow meters may not exist on all gaseous and liquid feedstocks and products. A turnaround may be required to install the flow meters. The turnaround cycle for units varies between 2 to 5 years. EPA should specify: (1) the reporter must install the flow meters during the next scheduled turnaround after January 1, 2010; and (2) until such time as a flow meter is installed, the reporter may estimate the flow and document the method used for estimating the flow in the records required to be maintained under §98.247.

Response: Please see Section II.G of the preamble for the response to this comment.

Commenter Name: See Table 1

Commenter Affiliation:

Document Control Number: EPA-HQ-OAR-2008-0508-0423.2

Comment Excerpt Number: 125

Comment: Reporters that are using the mass balance methodology are required in §98.244(a)(2) to measure the volume of each gaseous and liquid feedstock and product continuously using a flow meter. Flow meters may not exist on all gaseous and liquid feedstocks and products. A turnaround may be required to install the flow meters. The turnaround cycle for units varies between 2 to 5 years. EPA should specify in the final rule: (1) the reporter must install the flow meters during the next scheduled turnaround after January 1, 2010; and (2) until such time as a flow meter is installed, the reporter may estimate the flow and document the method used for estimating the flow in the records required to be maintained under §98.247.

Response: Please see Section II.G of the preamble for the response to this comment.

Commenter Name: See Table 2

Commenter Affiliation:

Document Control Number: EPA-HQ-OAR-2008-0508-0433.2

Comment Excerpt Number: 59

Comment: The monitoring and QA/QC requirements for Petrochemical Production need to define how to interpret the term "continuously with a flow meter" in terms of data reduction similarly to other rules like continuously one data point every 15 minutes.

Response: The phrase cited by the commenter was used in section 98.243(b)(2)(i) of the proposed rule. To clarify the requirement, the word "continuously" has been deleted from the final rule (now section 98.243(c)(1)). A facility must measure and report the total volume of feedstock consumed or product produced during each monthly monitoring period.

Commenter Name: Lloyd Stone

Commenter Affiliation: Westlake Chemical Corporation

Document Control Number: EPA-HQ-OAR-2008-0508-0442.1

Comment Excerpt Number: 18

Comment: Westlake requests EPA to define "continuously" as it is used in subsection (b)(2). It could be inferred that continuous is defined out of the definition of CEMS (i.e., one discrete reading every 15 minutes). EPA needs to clarify the use of this term.

Response: Please see the response to comment EPA-HQ-OAR-2008-0508-0433.2, excerpt number 59.

Commenter Name: See Table 1

Commenter Affiliation:

Document Control Number: EPA-HQ-OAR-2008-0508-0423.2

Comment Excerpt Number: 126

Comment: Section 98.244(b)(2) requires that all feedstock and product flow meters be calibrated prior to the first reporting year, which presumably means that these calibrations must be done prior to January 1, 2010. This presents a significant problem for some petrochemical production sources in that a scheduled process shutdown may be necessary to calibrate some of these meters. We believe that EPA should allow until at least January 1, 2011 for the owner/operator to complete all required initial calibrations as the lack of a recent calibration should not significantly impact the quality of the carbon material balance.

Response: EPA acknowledges that for units and processes that operate continuously with infrequent outages, it may not be possible to meet the deadline for the initial calibration of a flow meter without removing the meter from service and shipping it to a remote location, thereby disrupting normal business operation. As a result, the final subpart X specifies that for process units that operate continuously with infrequent outages, the owner or operator may postpone the initial calibration until the next shutdown.

Commenter Name: See Table 1

Commenter Affiliation:

Document Control Number: EPA-HQ-OAR-2008-0508-0423.2

Comment Excerpt Number: 127

Comment: Section 98.244 (b)(2) also requires that the instruments be calibrated on at least an annual basis. If a facility can show through actual calibration data that the performance of the flow meter does not require recalibration even on an annual basis, the owner/operator should be allowed to calibrate in accordance with the recommendations of the manufacturer even if the calibration frequency is longer than annual.

Response: EPA acknowledges the concerns of the commenter. As a result, the final rule allows calibrations to be conducted at the minimum frequency recommended by the manufacturer.

Commenter Name: See Table 1

Commenter Affiliation:

Document Control Number: EPA-HQ-OAR-2008-0508-0423.2

Comment Excerpt Number: 128

Comment: Some of the petrochemical processes may use an on-line GC to determine feed stream composition. EPA should recognize this technology and allow for calibration of the on-

line GC using manufacturer's recommendations or perhaps EPA Performance Specification No. 9 in §98.244(b)(3).

Response: In response to this comment, EPA confirms that use of an on-line GC is allowed, and we have also revised and clarified the calibration procedures allowable under the rule. Specifically, a facility may calibrate the on-line GC according to the procedures specified in Performance Specification 9 in 40 CFR part 60, appendix B.

Commenter Name: Robert Rouse

Commenter Affiliation: The Dow Chemical Company

Document Control Number: EPA-HQ-OAR-2008-0508-0533.1

Comment Excerpt Number: 33

Comment: EPA Should Make the Calibration Requirements for Meters Associated with Gas and Liquid Feedstocks and Products More Flexible. 98.244(b)(2) requires that all feedstock and product flow meters be calibrated prior to the first reporting year, which presumably means that these calibrations must be done prior to January 1, 2010. This presents a significant problem for some petrochemical production sources in that a scheduled process shutdown may be necessary to calibrate some of these meters. Dow comments that EPA should allow until at least January 1, 2011 for the owner/operator to complete all required initial calibrations since the lack of a recent calibration should not significantly impact the quality of the carbon material balance. 98.244(b)(2) also requires that the instruments be calibrated on at least an annual basis. If a facility can show through actual calibration data that the performance of the flow meter does not require recalibration even on an annual basis, the owner/operator should be allowed to calibrate in accordance with the recommendations of the manufacturer, even if the calibration frequency is longer than annual. EPA Should Incorporate Provisions to Allow Use of On-Line GCs for Determining Feedstream or Product Carbon Content. 98.244(b)(3) - Some of the petrochemical processes may use an on-line GC to determine feed stream composition. EPA should recognize this technology and allow for calibration of the online GC using manufacturers' recommendations or perhaps EPA Performance Specification No. 9. Carbon Content Requirements for Liquid Waste Streams, Wastewater Streams, Vents to Control Devices, and Emissions to Atmosphere. If the owner/operator is allowed to consider the carbon content of liquid waste streams, wastewater discharges, vents to control devices, and emissions to atmosphere, then the owner/operator should be allowed to use process knowledge and engineering calculations in order to determine the carbon content of these streams.

Response: See the responses to comments EPA-HQ-OAR-2008-0508-0423.2, excerpt numbers 124, 126, 127, and 128.

Commenter Name: Gregory J. Bocchi

Commenter Affiliation: Vinyl Institute (VI)

Document Control Number: EPA-HQ-OAR-2008-0508-1030.1

Comment Excerpt Number: 2

Comment: Under the NPRM, facilities that do not operate an existing continuous emission monitoring system ("CEMS") must measure the mass rate or volume of each feedstock and product and record the results weekly. The Agency provides no explanation as to why weekly estimates are necessary to ensure reasonable annual carbon dioxide equivalent estimates. This

requirement would be overly burdensome as it would require VI member facilities to conduct the following tasks EACH calendar week: 1. Continuously measure and record the mass rate of each gaseous and liquid feedstock and weekly measure and record the mass rate of each solid feedstock; 2. Collect a sample of feedstock and product and measure the carbon content using an EPA-approved method such as a gas chromatograph; 3. Calibrate flow meters and weighing equipment initially and annually thereafter, unless the manufacture requires more frequent calibration; and 4. Document all calibrations, measurements, calculations, etc.

Response: Please see Section III.X.3 of the preamble for the response to this comment.

Commenter Name: David P. DiBoyan

Commenter Affiliation: International Carbon Black Association (ICBA)

Document Control Number: EPA-HQ-OAR-2008-0508-0678.1

Comment Excerpt Number: 5

Comment: Subpart X – 98.243(a)(2)(i) requires that each gaseous or liquid feedstock or product be continuously monitored and that each feedstock and product be analyzed weekly to determine carbon content. Similarly, Subpart X – 98.244(a)(3) states that samples of each grade or type of product of carbon black products produced must be collected and analyzed weekly. In both cases (continuous monitoring and weekly collection and analysis of the various grades), the ICBA believes these are unnecessary and will be extremely onerous to the industry, with no increased value or merit.

Response: With respect to the sampling and analysis frequency, please see Section III.X.3 of the preamble. The final rule also clarifies the flow monitoring requirement by deleting the word “continuously”. As explained in the response to comment EPA-HQ-OAR-2008-0508-0433.2, excerpt 2, the final rule requires measurement of the total flow during the monitoring period. In addition, even though a carbon black manufacturer may produce numerous grades of products, those products must meet customer specifications, such as the carbon content. To demonstrate that these specifications are met, the manufacturer must measure the composition of the product. For these reasons, we have determined that the requirements in the final rule do not impose an additional sampling and analysis burden on the industry.

7. PROCEDURES FOR ESTIMATING MISSING DATA

Commenter Name: Robert Rouse

Commenter Affiliation: The Dow Chemical Company

Document Control Number: EPA-HQ-OAR-2008-0508-0533.1

Comment Excerpt Number: 34

Comment: If the source can justify another method instead of averaging the values immediately preceding and following the missing data incident by using engineering calculations and process knowledge, EPA should allow this as an option to avoid under- or over-stating GHG emissions.

Response: At proposal, we developed an approach for dealing with missing data with minimal burden. We did not propose procedures that would require site-by-site evaluation and approval because they could be inconsistent and labor intensive to review and implement. The commenter

did not provide specific information on the possible other approaches to missing data, and therefore, we have not changed the missing data procedures for the final rule.

Commenter Name: See Table 1

Commenter Affiliation:

Document Control Number: EPA-HQ-OAR-2008-0508-0423.2

Comment Excerpt Number: 129

Comment: If the source can justify another method instead of averaging the values immediately preceding and following the missing data incident by using engineering calculations and process knowledge, EPA should allow this as an option to avoid under- or over-stating GHG emissions.

Response: Please see the response to EPA-HQ-OAR-2008-0508-0533.1, excerpt number 34.

8. DATA REPORTING REQUIREMENTS

Commenter Name: Robert Rouse

Commenter Affiliation: The Dow Chemical Company

Document Control Number: EPA-HQ-OAR-2008-0508-0533.1

Comment Excerpt Number: 35

Comment: The Proposed Reporting Requirements are Excessive and EPA Should Move Certain Reporting Elements to the Recordkeeping Requirements in 98.247. The proposed reporting requirements are excessive. The reporting requirements should be consistent with emissions inventory reporting requirements, and other supporting information should be part of recordkeeping. Other environmental reporting regulations do not require virtually all records to be included in submitted reports. In particular, the excessive portions of the reporting rule for petrochemical production processes are Sections 98.246(a)(7) and (a)(8). Submittal of elements such as each carbon content measurement and information on the calibration of each flow meter will not improve the overall quality of the GHG emission calculation. EPA should take into consideration that the owner/operator will be certifying that the information provided is true, accurate, and complete to the best of their knowledge, which is a significant responsibility. The bulk of the information requested in proposed 98.246(a)(7) and (a)(8) should be relocated to the recordkeeping requirements in 98.247.

Response: Please see Section III.X.3 of the preamble for the response to this comment.

Commenter Name: See Table 1

Commenter Affiliation:

Document Control Number: EPA-HQ-OAR-2008-0508-0423.2

Comment Excerpt Number: 130

Comment: The excessive portions of the reporting rule for petrochemical production processes are §§98.246(a)(7) and (a)(8). Submittal of elements such as each carbon content measurement and information on the calibration of each flow meter will not improve the overall quality of the GHG emission calculation. EPA should keep in mind that the owner/operator will be certifying

that the information provided is true, accurate, and complete to the best of his/her knowledge, which is a certification that ACC members take very seriously. The bulk of the information requested in proposed §§98.246(a)(7) and (a)(8) should be relocated to the recordkeeping requirements in §98.247.

Response: Please see Section III.X.3 of the preamble for the response to this comment.

9. COST DATA

Commenter Name: Gregory J. Bocchi

Commenter Affiliation: Vinyl Institute (VI)

Document Control Number: EPA-HQ-OAR-2008-0508-1030.1

Comment Excerpt Number: 3

Comment: According to EPA's Regulatory Impact Analysis for the Mandatory Reporting of Greenhouse Gas Emissions Proposed Rule (GHG Reporting) Cost Appendix, "[m]onitoring costs (for sampling and analysis) were considered minimal because it was assumed that all petrochemical facilities are already measuring the flows and composition of the feedstocks and products." The Agency assumes that 12 industrial engineer/technician hours would be sufficient for such sampling, at an annual cost of approximately \$600. VI believes that EPA has significantly underestimated the time and cost of monitoring and sampling required for each process unit. For example, because each process unit would have to sample both feedstock and product weekly, the minimum number of samples taken at a facility is likely to be 104 samples per unit (more for facilities with multiple process units and multiple feedstocks). Facilities would then be required to determine the carbon content of each sample using a gas chromatograph that meets ASTM standards or EPA methods. Any monitoring or sampling data already being done for production reasons likely would not meet this qualification. Even facilities with gas chromatographs on site are likely to find it more cost effective to hire out the sampling and analysis. In the aggregate, such sampling has the potential to exceed EPA's cost estimate by several orders of magnitude. Given the relative consistency in feedstock raw materials (i.e., ethylene) for EDC/VCM production, EPA has not provided a reasonable rationale as to why less frequent sampling, such as quarterly or annually would not be sufficient. VI Member companies only produce one intended primary product within their operating units, as opposed to a flexible operating unit, which produces different chemical products by alternating raw materials or feedstocks.

Response: For the material balance option in the final rule, facilities must sample and analyze feedstocks and products at least once per month. The cost impacts analysis in the Regulatory Impact Analysis (RIA) for the final rule, like the proposal RIA, does not include costs for these sampling and analysis activities because facilities already must determine the composition of products to ensure that they meet customer specifications, and feedstock compositions also must be known in order to properly operate the process. The final rule references a comprehensive list of EPA, ASTM, ASME and other methods that are valid means of conducting the required sampling and analysis for feedstocks and products. We are not aware of any other methods that facilities might be using, and the commenter did not mention any. For these reasons, we have determined that our estimate of burden is sound and that the rule does not impose additional sampling and analysis costs for feedstocks and products. With respect to the required frequency of monitoring, please see Section III.X.3 of the preamble.

Commenter Name: Gregory J. Bocchi
Commenter Affiliation: Vinyl Institute (VI)
Document Control Number: EPA-HQ-OAR-2008-0508-1030.1
Comment Excerpt Number: 4

Comment: Laboratory costs to collect and then analyze samples by gas chromatography typically run about \$100 for sample collection and \$150 for gas chromatograph analysis, for a total of \$250 per sample. Using 104 samples per year per process at \$250 per sample is \$20,800 per year per process unit. With 2 or 3 process units per site, this would be \$41,600 to \$62,400 per year per site. This cost is well above EPA's estimate of \$600 per year.

Response: As noted in the response to comment EPA-HQ-OAR-2008-0508-1030.1, excerpt number 3, we have not estimated costs for sampling and analysis for feedstocks and products because this information is already collected for process reasons. However, we have included sampling and analysis costs for supplemental fuel sampling and analysis. For the impacts analysis in the final RIA, the sampling collection costs were increased to \$100/sample. The final impacts analysis, like the proposed analysis, estimates analysis costs at \$150/sample, which is consistent with the cost cited by the commenter.

Commenter Name: Gregory J. Bocchi
Commenter Affiliation: Vinyl Institute (VI)
Document Control Number: EPA-HQ-OAR-2008-0508-1030.1
Comment Excerpt Number: 5

Comment: EPA's estimate that "an engineer would need, on average, 12 engineer/technician hours per year to compile and store data, perform calculations, and prepare the annual report" also seems woefully inadequate. The Agency's estimate of one hour for a technical engineer to review the rule and prepare required initial notifications is grossly underestimated, as is the estimate of 0.5 hours to prepare the initial records. Considering the proposed rule takes up more than 100 Federal Register pages, presuming that a single engineer will read the rule in an hour and then be prepared to collect the continuous records, make calculations, and review the material with the authorized designated representative, etc. within another 30 minutes is a serious underestimation. This underestimation is even more dramatic when the proposed compliance and enforcement provisions at § 98.8 are considered (e.g., "failure to retain records needed to verify the amount of GHG emission and "failure to calculate GHG emissions following the methodologies specified in this part"). According to EPA, costs were estimated for the time needed to review the rule and prepare required initial notifications and records." The first two years of implementation will have high reporting costs because various departments at a facility will need to be involved assumes that the "planning" step only occurs in the initial year of compliance. This is incorrect. Planning for this type of regulatory data collection must occur every year; it is ongoing cost of compliance. According to the Agency, quality assurance/quality control costs for planning, meetings and annual review total 127 engineer/technical hours. Based on VI Members' experience with similar EPA-required facility-wide data collection efforts, such as EPA's annual Toxic Release Inventory (TRI) reporting requirement, this estimate is 2-3 times too low. Moreover, the Agency's burden estimate referenced within these comments only represents the effort that would be required to comply with the Petrochemical Production Subpart of the NPRM and does not address the effort that would be required to comply with

other Subparts that may affect EDC production units (e.g. Part 94 Subparts A (General Provisions); C (General Stationary Fuel Combustion Sources); and II (Wastewater Treatment).

Response: The impacts analysis in the final RIA estimates 152 hr/yr/facility for an engineer/technician to conduct recordkeeping, sampling, calculations, and reporting. The final RIA also includes about 8 hr/yr/facility for management review and 15 hr/yr/facility for administrative staff. This is an increase from 78 hr/yr/facility shown in the tables in the proposal RIA (the 12 hours cited by the commenter was an error in the text of the proposal RIA that should have been 78 hours to be consistent with the tabulated quantity). The estimate in the final analysis is higher than at proposal primarily because we increased the time to collect and process fuel samples, increased the number of fuel samples for ethylene producers that comply with the combustion methodology option in the final rule instead of the mass balance option, and added a small amount of management and administrative time for every activity conducted by an engineer/technician.

The final RIA, like the proposal RIA, estimates 1.5 hours of engineer/technician time to review the rule and prepare initial records for an option that was rejected and is not required in the final rule (i.e., this is the estimate if the rule had required only the use of default emission factors and the annual production level).

The final RIA includes about 20 hr/yr/facility for planning, review, and ongoing training activities. These costs were also included in the proposal RIA, but they were mistakenly included in the hours for QA/QC activities. We disagree with the commenter's assessment that the annual planning and review burden for this rule should be comparable to the burden for the TRI. The TRI requires much more extensive recordkeeping and reporting and covers more compounds than this rule addresses.

Table 1

COMMENTS	AFFILIATE	DCN
Lorraine Krupa Gershman	American Chemistry Council	EPA-HQ-OAR-2008-0508-0423.1
Sarah B. King	DuPont Company	EPA-HQ-OAR-2008-0508-0604.1

Table 2

COMMENTS	AFFILIATE	DCN
James Greenwood	Valero Energy Corporation	EPA-HQ-OAR-2008-0508-0571.1 EPA-HQ-OAR-2008-0508-0571.2
Charles T. Drevna	National Petrochemical and Refiners Association	EPA-HQ-OAR-2008-0508-0433.1 EPA-HQ-OAR-2008-0508-0433.2

Table 3

COMMENTS	AFFILIATE	DCN
Karin Ritter	American Petroleum Institute (API)	EPA-HQ-OAR-2008-0508-0679.1
James Greenwood	Valero Energy Corporation	EPA-HQ-OAR-2008-0508-0571.1
William W. Grygar II	Anadarko Petroleum Corporation	EPA-HQ-OAR-2008-0508-0459.1