



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

Volume No.: 31

Subpart Y—Petroleum Refineries

September 2009

Subpart Y—Petroleum Refineries

**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 Y—Petroleum Refineries.

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 Y—Petroleum Refineries 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 Y—Petroleum Refineries.

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SUBPART Y—PETROLEUM REFINERIES

1. DEFINITION OF SOURCE CATEGORY

Commenter Name: D. Lawrence Zink

Commenter Affiliation: Montana Sulphur & Chemical Company Inc. (MSCC)

Document Control Number: EPA-HQ-OAR-2008-0508-0505.1

Comment Excerpt Number: 1

Comment: We seek clarification regarding the definition of a "petroleum refinery." The term "petroleum refinery" is found in the proposed regulation as 40 CFR 98.250 (74 FR 16683) and is referenced elsewhere. Specifically, it seems clear to us that the term "petroleum refinery" is not meant to apply to MSCC (or similar processors) since MSCC does not engage in the production of gasoline, kerosene, fuel oil, or other carbon based products, and since petroleum refineries (under the rule) are required elsewhere to account for sour gases sent off site for processing to such facilities as MSCC. If we were to account for these also, then these materials would be "double reported". However, the definition term goes on to describe that a petroleum refinery creates "other products" through "distillation, redistillation, cracking, or reforming of unfinished petroleum derivatives." This appears to be very broad and unclear. While we presume it is EPA's intent that this source category (petroleum refineries) is concerned primarily with converting crude oil, tar sands, etc. directly into petroleum (i.e. carbon based) fuel products, terms such as "...producing..." "other products" ... from unfinished "petroleum derivatives" could be interpreted in an overly broad and unintended manner. We seek clarification or a definition regarding the terms "distillation, redistillation, reforming, and unfinished petroleum derivatives" as it relates to the definition of a petroleum refinery source category. We suggest specific exclusion of "other" products from the definition where "carbon" is not the majority constituent, of the "product" and/or the "derivative" -- for example, products such as nitrogen, hydrogen, sulfur, fertilizers, ammonia, and other non-carbon-based or non-fuel materials. We note that even some obviously carbon-based products are specifically excluded for importers and exporters of petroleum products. We believe that sulfur and fertilizers should also specifically be added to that exclusion listing, as these are not GHG materials, regardless of the process of origin. From a practical perspective, we note, it is not feasible to determine whether fungible materials such as sulfur or fertilizer originated from a petroleum refinery or from natural gas operations or from some other industrial or mining activity; importers should not be asked to make such distinctions or segregations of commodity products. Along the same lines as noted above, it would be useful to better understand in the rule itself what EPA's intent is for determining the point at which an "unfinished petroleum derivative" as described in proposed 40 CFR 98.250 (74 FR 16683) becomes "finished." Again, this comment and request stems from the definition of a petroleum refinery. One of the minor elements typically found in crude oil is sulfur. As the crude oil is refined into other compounds, sulfur is typically removed from the stream and, in many cases, ends up as elemental sulfur (via a Claus plant, for example) or in some cases as H₂S and other non-fuel compounds. We read the proposed rule such that H₂S, elemental sulfur and other related compounds should not constitute "...other products ..." (p. 16683, proposed definition of a petroleum refinery). Again, we presume that when EPA refers to a petroleum refinery as a facility that produces "gasoline ... or other products ..." it only intends to include carbon-based products that are produced from and contain the petroleum (carbon) based feedstock. Products such as sulfur, SO₂, H₂S, NH₃, etc. (we presume) are not intended to cause a facility to meet the definition of a petroleum refinery, by themselves, and are not intended to be considered as

"petroleum products" or "unfinished petroleum derivatives". We would appreciate your concurrence with our conclusion. Again, we note that even some obviously carbon-based petroleum refinery products are specifically excluded in the proposal for importers and exporters of petroleum products.

Response: Please see the response in Section III.Y.3 of the preamble. We believe that these changes clarify that companies that use petroleum derivatives to make sulfur, sulfuric acid, ammonia or H₂S and similar non-carbon products are not considered petroleum refineries under subpart Y.

Commenter Name: John R. Evans

Commenter Affiliation: LyondellBasell Industries

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

Comment Excerpt Number: 4

Comment: As stated in EPA's Technical Support Document — Industry Overview and Current Reporting Requirements for Petroleum Refining and Petroleum Imports, "Refineries are among the industrial facilities that have to provide the most data to federal and state officials. EPA's Technical Support Document for the Petroleum Refining Sector: Proposed Rule For Mandatory Reporting of Greenhouse Gases, indicates that 92.9% of refining sector's GHG emissions come from two sources, combustion and catalytic coke operations. The remaining 7.1% of emissions come from eight distinct categories, including: H₂ plants (2.7%); Sulfur Plants (1.9%); Flaring (1.6%); Wastewater Treatment (0.43%); Blowdown (0.18%); Asphalt Blowing (0.10%); Delayed Coking (0.058%); Equipment Leaks (0.014%); Storage Tanks (0.007%); and Cooling Towers (0.003%). The burden associated with the collection of data as prescribed in the proposed rule is not warranted for small sources. Thus, a de minimis provision is clearly justified for the refining sector. EPA may wish to consider that the most cost effective reporting scheme for refineries would be to use a de minimis provision for all categories other than combustion and cat coke. Under this approach, emissions from all source categories would still be reported, but emissions would be determined by alternative methods selected by the operator and updated only when major operating changes are made. While refiners would still report a number for each of the 12 categories, prescriptive sampling, analysis, and rigorous calculations would be required for only the two categories which account for 92.9% of emissions. This would reduce the reporting burden by an estimated 83%.

Response: Please see Sections II.K and III.Y.3 of the preamble for responses to this comment.

Commenter Name: Karen St. John

Commenter Affiliation: BP America Inc. (BP)

Document Control Number: EPA-HQ-OAR-2008-0508-0631.1

Comment Excerpt Number: 30

Comment: Blowdown §98.6 (p. 16617): The EPA definition does not recognize that the stream may contain more than just natural gas. BP requests that the following definition from the GPSA be used instead: "The act of emptying or depressuring a vessel. This may also refer to the discarded material such as blowdown water from a boiler or cooling tower."

Response: Agreed, the definition in the general provisions was very specific to natural gas. We have revised the definition to be more general as requested by the commenter. Specifically, “*Blowdown* means the act of emptying or depressuring a vessel. This may also refer to the discarded material such as blowdown water from a boiler or cooling tower.”

Commenter Name: Jeffry C. Muffat

Commenter Affiliation: 3M Company

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

Comment Excerpt Number: 24

Comment: In 98.250 of Subpart Y, affected activities include “redistillation” of petroleum materials. The rule applicability should specifically exempt those many operations which could occur at locations which are not petroleum refineries by which may involve the redistillation of minor amounts of petroleum products prior to their use.

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

Commenter Name: See Table 1

Commenter Affiliation:

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

Comment Excerpt Number: 11

Comment: NPRA supports the development of an accurate CO₂e inventory and encourages EPA to consider only those sources and source categories which are significant to the inventory. In the preamble to the Mandatory Reporting Rule EPA lists the estimated covered entities, emissions and costs by subpart, table VIII-1, FR page 16597. As detailed in this table, emissions from many of the source categories contribute less than one percent to the overall inventory. If the source categories with contributions less than 1% of the inventory are removed, a full ninety-four percent (94%) of the CO₂e inventory is preserved. Given this, NPRA believes that EPA can produce an accurate and reliable inventory while at the same time removing sources and source categories from the rule. Removal of these small source categories would serve to reduce the administrative and reporting burden on the regulated community. Analysis of the wastewater treatment category’s contribution to the overall CO₂e inventory provides an illustrative example of how a source category can be removed from the reporting requirements without jeopardizing the integrity of the overall inventory. As indicated in table VIII-1 of the preamble, greenhouse gas emissions from the wastewater treatment category contribute zero percent to the overall inventory. In fact, table VIII- 1 indicates that EPA anticipates that zero wastewater treatment facilities will meet the threshold for reporting. It is presumed that table VIII- 1 indicates the number of facilities which consist of only wastewater treatment facilities, and which would meet or exceed the reporting threshold. This does not, however, account for the number of wastewater treatment facilities that are co-located at facilities that would otherwise have to report, (e.g., Petroleum Refining). Review of the technical support document for petroleum refining reveals that CO₂e emissions from wastewater treatment facilities co-located at petroleum refineries account for only 0.43 % of the petroleum refining sector’s aggregate CO₂e emissions and only 0.02% of the total CO₂e inventory. Petroleum refining constitutes about 5% of the total CO₂e inventory. A similar conclusion is reached when analyzing the petrochemical production sector. NPRA does not believe that the burden of monitoring, QA/QC, recordkeeping and reporting are warranted to estimate less than one percent of the CO₂e emissions from the petroleum refining

and the petrochemical production sectors. This is well with the range of either measurement or calculation error given the calculation methodologies. NPRA therefore proposes that reporting of wastewater treatment emissions be removed from petroleum refining and petrochemical production subsections.

Response: Please see Sections II.K and III.Y.3 of the preamble for responses to this comment. In regard to wastewater treatment, EPA is not going final with that source category at this time; please see Section III.II of the preamble and the relevant comment/response document.

Commenter Name: Robert Rouse

Commenter Affiliation: The Dow Chemical Company

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

Comment Excerpt Number: 36

Comment: In 98.250(a), EPA defines a Petroleum Refinery so broadly that it could be interpreted to include chemical facilities that use petroleum-based materials as raw materials. In order to ensure that this does not occur, EPA should modify the definition to note that it does not include those facilities that produce materials listed under the definition of "Petrochemical feedstocks" under 98.6: 98.250(a) - A petroleum refinery is any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, asphalt (bitumen) and other products through distillation of petroleum or through redistillation, cracking, or reforming of unfinished petroleum derivatives. This specifically excludes chemical facilities that use petroleum and/or petroleum derivatives as a raw material for the manufacture of chemicals, synthetic rubber, and a variety of plastics.

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

Commenter Name: Lorraine Krupa Gershman

Commenter Affiliation: American Chemistry Council (ACC)

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

Comment Excerpt Number: 135

Comment: For a 500,000 barrel of crude per day refinery (upper bounds for crude throughput), the methane emissions calculated by equation Y-8 is 1.3 metric tons per year. According to the Table Y-2 on page 16540 of the preamble, 99.3% of the U.S. refineries have direct GHG emissions that exceed 10,000 metric tons CO₂e per year. Thus, the emissions from uncontrolled blowdown systems from a large refinery are conservatively 0.013% of the refinery's total direct GHG emissions. Even if the intermediate products received from off-site are assumed to be equal to the crude rate, which is an over estimate, the blowdown emissions become 2.6 metric tons per year or 0.026% of the refinery's total GHG emissions. It is not clear to us why EPA would require the calculation and reporting of this data since the level of GHG emissions is so small. We fail to see how this data would help to support analysis of future policy decisions. (74 FR 16468.)

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

Commenter Name: Lorraine Krupa Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2008-0508-0423.2
Comment Excerpt Number: 131

Comment: In 98.250(a), EPA defines a Petroleum Refinery so broadly that it could be interpreted to include chemical facilities that use petroleum-based materials as raw materials. In order to ensure that this does not occur, EPA should modify the definition to note that it does not include those facilities that produce materials listed under the definition of “Petrochemical feedstocks” under 98.6: as follows: 98.250(a) A petroleum refinery is any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, asphalt (bitumen) and other products through distillation of petroleum or through redistillation, cracking, or reforming of unfinished petroleum derivatives. This specifically excludes chemical facilities that use petroleum and/or petroleum derivatives as a raw material for the manufacture of chemicals, synthetic rubber, and a variety of plastics.

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

Commenter Name: Dan F. Hunter
Commenter Affiliation: ConocoPhillips Company
Document Control Number: EPA-HQ-OAR-2008-0508-0515.1
Comment Excerpt Number: 54

Comment: EPA’s “Technical Support Document for the Petroleum Refining Sector: Proposed Rule for Mandatory Reporting of Greenhouse Gases” shows that 98+% of the total refinery GHG emissions on a CO_{2e} basis are from combustion and catalytic coke (together 92.9%), H₂ plants (2.7%), Sulfur Plants (1.9%) and Flaring (1.6%). The remaining (0.8% - Other) can be broken down into 6 categories: Wastewater Treatment (0.43%), Blowdown (0.18%), Asphalt Blowing (0.10%), Delayed Coking (0.058%), Equipment Leaks (0.014%), Storage Tanks (0.007%), and Cooling Towers (0.003%). The proposed rule is overly burdensome and prescriptive for these smaller sources with very little added benefit to the overall total GHG emissions for EPA policy development. For example, the proposed rule requires refineries to comply with Subpart II when the GHG emissions from wastewater sources only make-up an estimated 0.43% of the refinery total. As mentioned earlier in these comments in Section I, ConocoPhillips recommends EPA structure the rule to not require reporting where the source category comprises a small percentage (e.g. <1%) of the total refinery GHG emissions. ConocoPhillips requests wastewater treatment, blowdown, asphalt blowing, delayed coking, equipment leaks, storage tanks, and cooling towers be excluded from the final rule.

Response: Please see Sections II.K and III.Y.3 of the preamble for responses to this comment. In regard to wastewater treatment, EPA is not going final at this time with that source category; please see Section III.II of the preamble and the relevant comment/response document.

Commenter Name: Dan F. Hunter
Commenter Affiliation: ConocoPhillips Company
Document Control Number: EPA-HQ-OAR-2008-0508-0515.1
Comment Excerpt Number: 15

Comment: Storage Tank - the definition is overly broad enough and could be interpreted to include sumps. Based on the methods in the subpart, it does not appear EPA intended to cover sumps as storage tanks. ConocoPhillips recommends specifically excluding sumps and other similar units. An example of where this has been done in the past is for the Organic Liquid Distribution MACT (§63.2406).

Response: The basic definition provided for storage tanks is consistent with other rules that define storage tanks. We do not think it is appropriate to place applicability constraints within the definition, especially within the general provisions. However, we have included language in subpart Y to clarify the types of storage tanks for which storage tank emissions are to be reported; this language is consistent with the language used in the Organic Liquid Distribution MACT (§63.2406). Specifically, we state that you do not need to calculate CH₄ emissions from storage tanks that meet any of the following descriptions: (1) units permanently attached to conveyances such as trucks, trailers, rail cars, barges, or ships; (2) pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere; (3) bottoms receivers or sumps; (4) vessels storing wastewater; or (5) reactor vessels associated with a manufacturing process unit.

Commenter Name: Lorraine Krupa Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2008-0508-0423.2
Comment Excerpt Number: 14

Comment: In §98.250 of Subpart Y, the definition of affected activities includes 'redistillation' of petroleum materials. The rule applicability should specifically exempt those many facilities which could occur at locations which are not petroleum refineries but which may redistill petroleum products prior to their use.

Response: We have clarified the definition of petroleum refinery by adding gasoline blending stocks and naphtha to the list of products and deleting the term "or other products." We believe that this change clarifies that companies that use petroleum derivatives to make petrochemicals, plastics, synthetic rubber, or products other than those listed are not considered petroleum refineries, whether or not they redistill or crack the petroleum derivatives.

Commenter Name: Deborah Seligman
Commenter Affiliation: New Mexico Oil and Gas Association (NMOGA)
Document Control Number: EPA-HQ-OAR-2008-0508-0603.1
Comment Excerpt Number: 12

Comment: EPA also proposes to include source types such as storage tanks that contribute a small percentage of a refinery's GHG emissions. Again, given the accuracy of the models used for climate change predictions, the effort required for calculating emissions, keeping the

associated records, and reporting the minor contributions is not justified. Refinery storage vessels that store higher vapor pressure materials are already required to meet stringent control requirements under Federal Clean Air Act regulations. So the additional information gained would not be useful in any future regulatory program designed to reduce GHG emissions. NMOGA believes that EPA already has sufficient information to estimate GHG emissions from refineries within a reasonable accuracy range. As noted earlier, EPA recognizes that refinery fuel consumption is the largest contributor to refinery GHG emissions and that fuel data is already reported to the Energy Information Agency (EIA). EPA should focus their resources on using the available information instead of creating an additional and costly burden on the regulated community.

Response: Please see Sections II.K and III.Y.3 of the preamble for responses to this comment. Given the lack of data on GHG emissions arising from a variety of petroleum refinery sources that have demonstrated control alternatives, we determined that the burden associated with collecting this additional information to be justified. With respect to data available from the EIA, we have determined that in order to collect facility-level data from petroleum refineries that is consistent with other reporters in terms of timing, reporting, and emissions verification procedures, we are not able to rely upon EIA data. Collection of data in a central system will allow EPA to electronically verify and publish the data quickly and to handle confidential business information in accordance with the Clean Air Act. In addition, EPA is collecting data that is not currently reported to EIA, such as carbon content.

Commenter Name: Gregory A. Wilkins

Commenter Affiliation: Marathon Oil Corporation

Document Control Number: EPA-HQ-OAR-2008-0508-0712.1

Comment Excerpt Number: 66

Comment: Marathon opposes calculating emissions for insignificant sources. It is overly burdensome to require stringent reporting requirements for sources that will only result in a small percentage of emissions for a facility. These de minimis sources can include but are not limited to fugitive emissions, tanks, wastewater treatment, oil water separators, sulfur recovery units, flaring, miscellaneous process vents, loading losses, vapor recovery units, asphalt blowing, delayed coking, portable and stationary engines, and reformers to name a few. A specific example on how some sources are insignificant can be found in EPA's technical background document "Technical Support Document for the Petroleum Refining Sector". On page 12 EPA shows data indicating that Asphalt Blowing (0.1%), Delayed Coking (0.058%), Equipment Leaks (0.014%), Storage Tanks (0.007%), Wastewater Treatment (0.43%), and other sources combined are less than 0.8% of a refinery's total GHG emissions.

In addition the data shows flaring to be 1.6% of emissions from a refinery which we estimate as being high. Also the Sulfur Plant is shown on the graph to contribute roughly 1.9% of overall GHG emissions. If you were to add these insignificant sources together, one would find that they represent only 4.3% of total refinery emissions yet require a large portion of the work to estimate emissions. By having a de minimus threshold of 5% Marathon could reduce the cost anti labor burden of this rule by an estimated 50%. Additionally, many other registries offer a de minimis threshold including the California mandatory reporting rule anti the Climate Registry.

Marathon asks that EPA consider the information provided in this section as evidence that these sources are insignificant for the average refinery. Marathon in conjunction with a third party,

conducted a de minimis review in 2008 using 2007 data for some of these sources outlined above. Marathon looked at an average refinery and computed using engineering estimates and best available data the CO₂e for sources considered insignificant. These results for this average refinery are shown for sources that EPA does not include in their analysis including truck loading (Thermal Oxidizers) which Marathon concluded to be 0.3% of total emissions and non-road combustion (stationary and portable engines) which were calculated to be 0.3%. Along with specific de minimis sources, the emissions of both N₂O and CH₄ should be completely exempted or considered de minimis. EPA estimates these emissions in the TSD for Subpart IT to be 0.09% for N₂O and 0.87% for CH₄ on a CO₂e basis. Per EPA's calculations, these emissions are very small, and should be exempted from this reporting rule.

Response: Please see Sections II.K and III.Y.3 of the preamble for responses to this comment.

Commenter Name: Christina T. Wisdom

Commenter Affiliation: Texas Chemical Council (TCC)

Document Control Number: EPA-HQ-OAR-2008-0508-0638.1

Comment Excerpt Number: 7

Comment: We request that EPA revise the definition of the petroleum refining source category by removing the word "redistillation" from the definition of the petroleum refining source category in proposed § 98.250(a). We further propose that EPA revise the definition of the petroleum refinery source category equipment in proposed § 98.250(b) by deleting references to any equipment whose presence would not be unique to a petroleum refinery including blowdown system; storage tanks; process equipment components (compressors, pumps, valves, pressure relief devices, flanges, and connectors) in gas service; marine vessel, barge, tanker truck, and similar loading operations; flares; and land disposal units. In addition, we propose that EPA revise the definition of "petroleum product" by deleting reference to processing "other petroleum-based feedstocks" in the first sentence of the definition.

Response: Please see our response in Section III.Y.3 of the preamble. Additionally, we note that paragraph (b) of § 98.250 provides a listing of those sources "at petroleum refineries" to which the reporting requirements of Subpart Y apply, and is not intended to be a list of processes that are unique to petroleum refineries.

Commenter Name: Sally V. Allen

Commenter Affiliation: Gary-Williams Energy Corporation

Document Control Number: EPA-HQ-OAR-2008-0508-0982.1

Comment Excerpt Number: 6

Comment: The regulations should include an optional de minimis provision which would significantly facilitate reporting on generally acknowledged categories which make up less than 20% of average refinery emissions. EPA's Technical Support Document shows that 92.9% of total refinery GHG emissions on a CO₂e basis are from combustion and catalytic coke. The remaining 7.1% of emissions come from five categories: H₂ plants (2.7%); Sulfur Plants (1.9%), Flaring (1.6%); and Other (0.8%). The "other" category includes wastewater treatment, blowdown, asphalt blowing, delayed coking, equipment leaks, storage tanks and cooling towers. Emissions from all categories other than combustion and catalytic coke should be considered de minimis and reported by an alternative method selected by the operator, exempted from annual

reporting and updated only when major operating changes are made. The remaining emissions calculations, including especially flare calculations, are onerous and time-consuming and a relatively insignificant source of GHG emissions. Not all SBRs have the same number of emission categories. For example, a refinery with no hydrogen plant, asphalt production or delayed coker would have a much lower reporting burden. The de minimis provision would result in a much fairer distribution of the reporting burden.

Response: Please see Sections II.K and III.Y.3 of the preamble for responses to this comment.

Commenter Name: Lorraine Krupa Gershman

Commenter Affiliation: American Chemistry Council (ACC)

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

Comment Excerpt Number: 136

Comment: It is unnecessary to calculate methane emissions from storage tanks, as required in §98.253(m). The methane emissions from storage tanks other than those processing unstabilized crude oil for a 500,000 barrel of crude per year refinery (upper bounds for crude throughput) using equation Y-15 is 0.05 metric tons per year. According to the Table Y-2 on page 16540 of the preamble, 99.3% of the U.S. refineries have direct GHG emissions that exceed 10,000 metric tons CO₂e per year. Thus, the methane emissions from storage tanks other than unstabilized crude oil from a large refinery are conservatively 0.0005% of the refinery's total direct GHG emissions. Even if the intermediate products received from off-site are assumed to be equal to the crude rate, which is an over estimate, the tank emissions become 0.1 metric tons per year or 0.001% of the refinery's total GHG emissions. This level of reporting is not consistent with EPA's stated intended purpose of the rule which is to support analysis of future policy decisions.

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

Commenter Name: Karen St. John

Commenter Affiliation: BP America Inc. (BP)

Document Control Number: EPA-HQ-OAR-2008-0508-0631.1

Comment Excerpt Number: 54

Comment: Storage Tank §98.6 (p. 16626): The use of the word "other" in EPA's definition of "Storage Tank" is confusing: "storage tank means other vessel that is designed to contain an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water and that is constructed entirely of non-earthen materials (e.g., wood, concrete, steel, plastic) that provide structural support." In addition, the definition is broad enough and could be interpreted to include sumps. Based on the methods in the subpart it does not appear EPA intended to cover sumps as a storage tank. BP recommends specifically excluding sumps and or other similar units. An example of a rule (63.2406) where EPA has done this is below. Storage tank means a stationary unit that is constructed primarily of nonearthen materials (such as wood, concrete, steel, or reinforced plastic) that provide structural support and is designed to hold a bulk quantity of liquid. Storage tanks do not include: (1) Units permanently attached to conveyances such as trucks, trailers, rail cars, barges, or ships; (2) Pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere; (3) Bottoms receivers; (4) Surge

control vessels; (5) Vessels storing wastewater; or (6) Reactor vessels associated with a manufacturing process unit.

Response: Please see the response to comment EPA-HQ-OAR-2008-0508-0515.1, Excerpt No. 15 of this document. We have included in subpart Y language similar to that suggested by the commenter to clarify the types of vessels that do not need to report under the storage tank provisions.

Commenter Name: See Table 2

Commenter Affiliation:

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

Comment Excerpt Number: 199

Comment: §98.253(j). EPA's intended emission source covered by the provision for process vents beyond those in §98.253(a)-(i) is unclear. EPA should clarify that this provision applies to process vents released to the atmosphere after controls, if they exist. The provision should include a de minimis reporting level based on carbon content, flow rate, and/or emissions. EPA has already determined the process vents with the majority of the GHG emissions and specified emission methodologies for them in §98.253(a)-(i). Thus, the emissions from these vents are probably insignificant compared to the total GHG emissions from the refinery.

Response: We agree that the scope of sources covered in §98.253(j) was unclear. It was not our intent to require reporting of every process vent or safety device vent in the refinery. We have added a definition of process vent to clarify pressure relief devices are not considered process vents. Additionally, we added concentration thresholds for selected GHGs. If the vent gas cannot reasonably be expected to exceed these thresholds, reporting the GHG emissions for these vents is not required. In regard to a de minimis provision, please see Sections II.K and III.Y.3 of the preamble for responses to this comment.

Commenter Name: See Table 2

Commenter Affiliation:

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

Comment Excerpt Number: 183

Comment: §98.250(a). EPA should clarify the definition of the source category while it includes facilities engaged in producing lubricants, does not include facilities with the sole purpose of producing lubricants by blending of feedstocks (or base oils) where the facilities do not distill, redistill, crack or reform petroleum derivatives.

Response: We do not see a need to clarify the definition further because the definition already excludes these types of operations. Through this response, we agree that facilities that only blend base oils or other feedstocks to produce lubricating oils are not petroleum refineries if they do not distill petroleum or redistill, crack or reform unfinished petroleum derivatives.

Commenter Name: See Table 2

Commenter Affiliation:

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

Comment Excerpt Number: 182

Comment: 98.250(a). EPA should clarify that the definition of the source category does not include facilities where the equipment engaged in activities specified in §98.250(a) is shutdown and the facility operates only as a fuels distribution terminal.

Response: We do not see a need to clarify the definition further because the definition already excludes these types of operations. If the refining operations are shutdown, then the facility is not “engaged in” producing gasoline, etc., through the distillation of petroleum or redistillation, cracking or reforming of unfinished petroleum derivatives. Through this response, we also clarify that facilities serving solely as fuel distribution terminals are not petroleum refineries because they do not distill petroleum or redistill, crack or reform unfinished petroleum derivatives.

Commenter Name: See Table 2

Commenter Affiliation:

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

Comment Excerpt Number: 180

Comment: API requests that EPA explicitly exclude the two small (combined 3,300 bbls/day) middle distillate "topping" plants ("Topping Plants") located at the Prudhoe Bay and Kuparuk Fields on the North Slope of Alaska from coverage as petroleum refineries under 40 CFR Part 98 Subpart Y. The Topping Plants produce what is referred to as arctic heating fuel, that is similar to diesel, and a small quantity of jet fuel (approximately 4% of the total production). The majority of the arctic heating fuel is used as oil well freeze protection fluids as part of the field drilling operations. It is not combusted. The jet fuel is burned in company aircraft that are used for Kuparuk and Prudhoe Bay operations. A portion of the arctic heating fuel is combusted in emission sources on the North Slope at facilities that will likely be subject to Subpart C reporting if greater than 25,000 metric tons per year. A small portion of the production (approximately 2 %) is sold to third party oil and gas operators for combustion in equipment at other North Slope oil fields. Regulation of the Topping Plants under 40 CFR Part 98 Subpart Y does not appear necessary to capture reporting of the vast majority of the distillates produced at these topping plants and instead would lead to double and possibly triple reporting of the same volume. This exemption request is similar to past exemptions that recognize the uniqueness of the North Slope and its challenges. See for example NSPS KKK at 40 CFR 60.633(e) where EPA recently exempted certain North Slope equipment from the routine monitoring requirements of 40 CFR 60.482.

Response: We believe that these “topping plants” are petroleum refineries and should report their GHG emissions under subpart Y. We specifically included these plants in developing our impact estimates for subpart Y. Subpart Y requires petroleum refineries to report process emissions, thus the potential future use of the product produced at the refinery (e.g., as oil well freeze protection fluids versus fuel) is irrelevant in determining whether it is appropriate to include the process emissions from their production. The cited NSPS (part 60 subpart KKK) is applicable to natural gas processing plants and not specifically petroleum refineries. Similar exclusions are not included in the refinery NSPS (part 60 subpart J/Ja) or the refinery MACT standards (part 63 subparts CC and UUU). EPA concludes that, given the scope of the petroleum market, the size of GHG emissions from petroleum, and the importance of petroleum to the

economy, it is necessary for our accounting to be as comprehensive as possible. We seek as full an understanding of GHG emissions from the petroleum industry as possible.

Commenter Name: See Table 2

Commenter Affiliation:

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

Comment Excerpt Number: 178

Comment: API supports including a de minimis condition. The cost burden goes beyond just the measurement and verification. QA/QC, reporting, and monitoring requirements should also be relaxed for insignificant emission sources. API requests a provision that allows a simplified method or limited studies to demonstrate de minimis. Sources determined to be inconsequential would also not have to comply with QA/QC, reporting, and monitoring requirements. The sources could be revisited every few years to confirm that the methods are still applicable. For example, under AB32: The operator may elect to designate as de minimis one or more sources that collectively produce no more than 3 percent of the facility's total CO₂ equivalent emissions. The operator may estimate emissions for these de minimis sources using alternative methods of the operator's choosing, subject to the concurrence of the verification team that the use of such methods provides reasonable assurance that the emissions so designated and estimated do not exceed the applicable de minimis limits. Some potential de minimis emission sources from refining include: fugitive emissions, tanks, wastewater treatment, oil water separators, sulfur recovery units, flaring, miscellaneous process vents, loading losses, vapor recovery units, and reformers for refineries. The API Compendium notes the following non-GHG sources which may be present at refineries: Cooling Towers; Equipment Leaks from liquid process streams⁹; Product Tanks (e.g. gasoline tanks)¹; Oil/Water Separators; and Process Drains. Marketing terminals may also be sources of VOC emissions (such as from equipment leaks and storage tanks), but not sources of GHG emissions. API members have concluded that there are no GHG emissions from these sources, and therefore they should not be included in a GHG inventory. In EPA's "Technical Support Document for the Petroleum Refining Sector: Proposed Rule for Mandatory Reporting of Greenhouse Gases", it shows on page 12 that Asphalt Blowing, Delayed Coking, Equipment Leaks, Storage Tanks, Wastewater Treatment, and other sources are equal to less than 0.8% of a total refineries GHG emissions. In addition the pie chart shows flaring to be 1.6% of emissions from a refinery which industry believes is an over-estimate. Also the Sulfur Plant is shown on the graph to contribute roughly 1.9% of overall GHG emissions. Adding these insignificant sources together, indicates that they represent only 4.3% of total refinery emissions yet require a large portion of the work to estimate emissions. API estimates that having a de minimis threshold of 5%, could reduce the compliance cost and labor burden by 50%. API is conducting a survey of elements related to EPA's cost assumptions for the reporting rule. API will provide the results of the survey in a separate submittal. Also in the same Technical Document for Petroleum Refineries, on page 18 there is a graph showing the breakdown of greenhouse gases. N₂O and CH₄ together account for less than 1% (on a CO₂e basis) of an average refinery's emissions. These should also be able to be counted in the de minimis threshold.

Response: Please see Sections II.K and III.Y.3 of the preamble for responses to this comment. In regard to wastewater treatment, EPA is not going final at this time with that source category; please see Section III.II of the preamble and the relevant comment/response document.

Commenter Name: Karen St. John
Commenter Affiliation: BP America Inc. (BP)
Document Control Number: EPA-HQ-OAR-2008-0508-0631.1
Comment Excerpt Number: 102

Comment: BP requests that EPA explicitly exclude the two small (combined 3,300 bbls/day) middle distillate "topping" plants ("Topping Plants") located at the Prudhoe Bay and Kuparuk Fields on the North Slope of Alaska from coverage as petroleum refineries under 40 CFR Part 98 Subpart Y. The Topping Plants produce what is referred to as arctic heating fuel, which is similar to diesel, and a small quantity of jet fuel (approximately 4% of the total production). The majority of the arctic heating fuel is used as oil well freeze protection fluids as part of the field drilling operations. It is not combusted. The jet fuel is burned in our own aircraft that are used for Kuparuk and Prudhoe Bay operations. A portion of the arctic heating fuel is combusted in emission sources on the North Slope at facilities that will likely be subject to Subpart C reporting if greater than 25,000 metric tons per year. A small portion of the production (approximately 2 %) is sold to third party oil and gas operators for combustion in equipment at other North Slope oil fields. Regulation of the Topping Plants under 40 CFR Part 98 Subpart Y (Section 98.250) does not appear necessary to capture reporting of the vast majority of the distillates produced at these topping plants and instead would lead to double and possibly triple reporting of the same volume. This exemption request is similar to past exemptions that recognize the uniqueness of the North Slope and its challenges. See for example New Source Performance Standards (NSPS) KKK for Equipment Leaks from Onshore Natural Gas Processing Plants at 40 CFR 60.63 3(e) where EPA recently exempted certain North Slope equipment from the routine monitoring requirements of 40 CFR 60.482.

Response: Please see the response to comment EPA-HQ-OAR-2008-0508-0679.1, Excerpt No. 180 of this document.

Commenter Name: Rich Raiders
Commenter Affiliation: Arkema Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0511.1
Comment Excerpt Number: 60

Comment: In proposed Subpart Y, EPA requires certain reporting requirements to refinery sulfur recovery plants. Arkema supports the EPA definition of "sulfur recovery plant" at proposed 40 CFR 98 that clearly states that any sulfur recovery plant subject to proposed 40 CFR 98 Subpart Y must be located at a refinery.

Response: We recognize that other rules (e.g., 40 CFR Part 60, subpart J/Ja) include off-site sulfur recovery processes in the definition of the affected sources. However, for the purposes of subpart Y, the petroleum refinery must report the CO₂ included in the sour gas stream sent for off-site processing, so requiring the off-site facility to account for these emissions would require unnecessary overlapping reporting of these emissions.

Commenter Name: See Table 2
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0679.1
Comment Excerpt Number: 205

Comment: §98.253(m) – The CH₄ emissions from storage tanks other than those processing unstabilized crude oil for a 500,000 barrel of crude per year refinery (upper bounds for crude throughput) using equation Y-15 is 0.05 metric tons per year. According to the Table Y-2 on p. 16540 of the preamble, 99.3% of the U.S. refineries have direct GHG emissions that exceed 10,000 metric tons CO₂e per year. Thus, the CH₄ emissions from storage tanks other than unstabilized crude oil from a large refinery are conservatively 0.0005% of the refineries total direct GHG emissions. Even if the intermediate products received from off-site are assumed to be equal to the crude rate, which is an over estimate, the tank emissions become 0.1 metric tons per year or 0.001% of the refinery’s total GHG emissions. This level of reporting is not consistent with EPA’s stated intended purpose of the rule which is to support analysis of future policy decisions (p. 16468).

Response: Please see Section III.Y.3 of the preamble for the response to this comment. Note: we have interpreted this comment as referring to 500,000 bbl/day (rather than bbl/year) as an upper bound crude throughput based on refinery capacities reported by EIA.

Commenter Name: Karen St. John
Commenter Affiliation: BP America Inc. (BP)
Document Control Number: EPA-HQ-OAR-2008-0508-0631.1
Comment Excerpt Number: 51

Comment: EPA does not define the terms “Process Unit” or “Process Vent”. These terms are used throughout the rule and need clarification.

Response: EPA agrees with this comment. Section 98.6 in the final rule defines “process vent” as “a gas stream that: (1) is discharged through a conveyance to the atmosphere either directly or after passing through a control device; (2) originates from a unit operation, including but not limited to reactors (including reformers, crackers, and furnaces) and separation equipment for products and recovered byproducts; and (3) contains or has the potential to contain GHG that is generated in the process. Process vent does not include safety device discharges, equipment leaks, gas streams routed to a fuel gas system, discharges from storage tanks, and in-situ sampling systems (online analyzers).” The final rule also defines “safety device”.

The term “process unit” is used in several of the terms that are defined in subpart A, and it is used directly in subpart X. In each case, the term refers to a distinct sequence or group of equipment that is used to produce a material that is part of a source category subject to reporting. For example, a facility may have two steam crackers, each with its own train of separation equipment to produce ethylene and other products, which means the facility has two ethylene process units. To clarify this point, the final rule defines “process unit” as “the equipment assembled and connected by pipes and ducts to process raw materials and to manufacture either a final product or an intermediate used in the onsite production of other products. The process unit also includes the purification of recovered byproducts.”

Commenter Name: Sam Chamberlain
Commenter Affiliation: Murphy Oil Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0625
Comment Excerpt Number: 38

Comment: Under Subpart Y of the proposed rule, we noted that Section 98.252(g) requires refinery sources to include fugitive methane emissions in the annual GHG report. We request that EPA rescind this requirement. We assert that the environmental benefit from reporting these emissions is negligible and does not justify the additional regulatory burden. The contribution of methane emissions from fugitive sources is very small when compared to the refinery's overall CO₂e emissions. We offer the following in support of this request. We noted on page 16540 of the proposed rule that EPA used information contained in the Petroleum Refineries TSD (EPA-HQ-OAR-2008-0508-0025) in developing reporting requirements for this source category. We also noted on page 16542 of the proposed rule that EPA acknowledged "the small (less than 1%) contribution of other emissions sources at the refinery that make up the total GHG emissions from the facility". In reviewing the Petroleum Refinery TSD, Sections 3.8 and Figure 2 outline that "[f]ugitive methane emission sources are projected to only contribute 0.8% of a typical refinery's total GHG emissions". The Petroleum Refinery TSD further mentions that : "[m]ethane emissions from process equipment leaks are expected to be small compared to other GHG emission sources at a typical refinery". Under Section 3.8, methane emissions from process equipment leaks are included in the same list of fugitive methane emission sources as blow down systems, delayed coking unit depressurization and coke cutting, asphalt blowing, and wastewater treatment (including sludge digestion). That section goes on to mention that methane emissions from un-stabilized crude, crude oil loading and storage, and cooling towers are expected to be negligible. In Table 3-39 of the Inventory of US GHG Emissions and Sinks: 1990-2006 (EPA 430-R-08-005), methane emissions from petroleum refining sources account for 0.6 Tg CO₂e emissions from the Petroleum Systems sector, or 2.1% of the CO₂e emissions from this Sector. In comparison to overall US GHG emissions of 7054.2 Tg CO₂e, methane emissions from refining sources in the Petroleum Systems sector account for less than 0.01% of all US GHG emissions, and methane emissions from the entire Petroleum Systems Sector account for 0.4% of all US GHG emissions. In reviewing the Background Technical Support Document for the "Fugitive Emissions Reporting from the Petroleum and Natural Gas Industry" (EPA-HQ-OAR-2008-0508-0023), we noted that 28.4 million metric tons of CO₂e emission were attributed to methane emissions from the petroleum industry (according to the Inventory of US GHG Emissions and Sinks: 1990-2006 (EPA 430-R-08-005). Under Section A.3 of the Background TSD, we noted that crude oil refining processes "accounted for slightly over 2% of total [methane] emissions from the petroleum industry because most of the [methane] in crude oil is removed or escapes before the crude oil is delivered to the petroleum refineries." The Background TSD further comments, under Section B, that: "[w]here emissions from a source were greater than one percent of the national emissions from the petroleum or natural gas industry they were considered to be a significant source.". The Background TSD goes on to develop a "Decision Process for Emission Source Selection" in Figure 1 and details very specific source contributions in Appendix A. Considering the information provided in the Background TSD, we assert that EPA's proposal to include fugitive methane emissions in Section 98.252(g) is counter to the Agency's own supporting documents. As referenced in Section 6.1.1 of the API Compendium of GHG Emission Methodologies for the Oil and Gas Industry (February 2004), a study was completed to establish the relative contribution of methane emissions at a 50,000 to 99,000 Bbl/day capacity refinery. During the study, the refinery identified process components containing methane. For many of the components, additional tagging and monitoring was required because refinery leak detection and repair ("LDAR") programs do not require monitoring of non-VOC components. For purposes of the LDAR program, non-VOC containing streams are less than 10% VOCs and methane is not considered a VOC. After monitoring over 8,000 components and applying control effectiveness estimates (Protocol for Equipment Leak Emission Estimates, EPA 453/R-95-017) to those components subject to the normal LDAR

program (e.g. applied to refinery fuel gas system components but not to natural gas system components), the study estimated annual methane emissions at 765 tonnes CO₂e per year. This amounts to 0.11% of the refinery's GHG emissions, when compared to the annual GHG emission from this refinery (exclusive of fugitive methane sources) of 669,829 tonnes CO₂e. Murphy along with its refinery peers has a long history of fugitive monitoring pursuant to state and federal regulations. The amount of emissions that may be generated in-between fugitive measurements is so small compared the relative size of emissions from other refinery sources, the level of effort to try and quantify these emissions is burdensome and will require significant additional resources and would only result in a best guess. Murphy recommends EPA eliminate the requirement to try and quantify fugitive emission sources. The fugitive monitoring programs in place are designed to eliminate emissions and these programs are already monitored and audited by state and federal agencies. Considering the overall amount of GHG emissions attributable to methane emissions from fugitive emission sources at petroleum refineries, we recommend that EPA rescind the proposal to require reporting of these sources. In requiring refineries to report on these sources, in concert with the reporting certification requirements proposed in Section 98.3, EPA is adding an additional level of monitoring and recordkeeping burden to refineries that is unwarranted when compared to the overall benefit of including this level of detail in future policy decisions. We also believe that EPA underestimated the cost burden to regulated facilities when developing the Regulatory Impact Analysis for this portion of the proposed rule (EPA-HQ-OAR--2008-0508-0002). In order to identify the methane emissions from fugitive sources and ensure that annual GHG emission reports withstand the level of scrutiny suggested under Subpart A of the proposed rule, most refiner's will undertake a component tagging and monitoring program that will add many previously unmonitored components to the LDAR program. Refiner's have well-established LDAR programs and routinely achieve lower leak rates than those suggested in Appendix A of the Petroleum Refinery TSD and the Protocol for Equipment Leak Emission Estimates. In addition, most of the refiner's LDAR programs now operate under enhanced requirements, according to information published on EPA's web site (<http://www.epa.gov/compliance/resources/cases/civil/caa/petroleumrefinery-infosht.html>), nearly 90% of these programs are enhanced LDAR programs, thereby further reducing overall fugitive emission leak rates from the estimates considered as part of this proposed rulemaking.

Response: As noted by the commenter, we have very limited data on methane emissions from fugitive equipment leaks largely because methane is not considered a VOC. See 40 C.F.R. 51.100(s). As described in greater detail in our response to comments in Section III.Y.3 of the preamble, we find that the inclusion of reporting data for equipment is critical to support analysis of future policy decisions for petroleum refineries. The commenter first applied "control effectiveness estimates" for the LDAR program for the refinery fuel gas components prior to projecting methane emissions from equipment leaks to be only 0.11 percent of the refinery's GHG emissions. However, as methane is not a VOC and the traditional LDAR programs exclude fuel gas systems and potentially other high- methane-containing gas streams (if the non-methane VOC content does not exceed applicability thresholds), assuming these methane emissions are currently controlled by existing LDAR programs is inappropriate. Also as noted by the commenter, LDAR programs are effective at reducing emissions from fugitive equipment leaks. Consequently, applying an LDAR program to these streams is a specific policy that we would like to evaluate, and obtaining credible methane emission estimates for these sources is critical for this analysis. On the other hand, we recognize that requiring LDAR type monitoring for this reporting rule is a substantial burden. Therefore, in order to minimize the monitoring, recordkeeping, and reporting burden associated with these sources, we provide, as proposed, a very simple method to calculate the GHG emissions from equipment leaks when measurement

(or process count) data are not readily available. As such, there is very little cost associated with the requirements to report methane emissions from fugitive equipment leaks. In regard to the cost burden to regulated facilities, please see Section III.Y.3 of the preamble.

Commenter Name: Gregory A. Wilkins

Commenter Affiliation: Marathon Oil Corporation

Document Control Number: EPA-HQ-OAR-2008-0508-0712.1

Comment Excerpt Number: 78

Comment: Marathon interprets that this category [process vents] would include small refinery streams such as thermal oxidizers controlling wastewater treatment emissions, emissions from loading controls that go to a vapor destruction device, and process vents that are sent to a control device to comply with regulatory requirements (for example Subpart J, Benzene Waste NESHAP and Subpart BB). These streams have low flow, a low BTU value, and are low pressure (so they are not able to be sent to the flare). There is not any useful heat or energy gained from these streams. For the reasons stated, these streams should be included in this category. Marathon requests that EPA insert clarifying language into this category specifying the inclusion of the above identified streams, cold process vents (where gas is vented without combustion), and other miscellaneous refinery streams.

Response: We have added a definition of process vents to help clarify the process vent requirements (see response to comment EPA-HQ-OAR-2008-0508-0631.1, Excerpt No. 51, on page 14 of this document). While process vents include gas streams discharged to the atmosphere either directly or after passing through a control device, Subpart Y also clarifies that the process vent provision applies only to vents that are not otherwise covered in other provisions of Subpart Y. For thermal combustion units (including incinerators and thermal oxidizers), these process vents are required to report following the requirements in Subpart C as specified in §98.252(a).

For thermal control devices that use natural gas, Subpart C allows its Tier 1 and 2 methods to be used for combustion devices rated at 250 MMBtu/hr and less, which only requires the reporting of emissions from the combustion of fuels for which emission factors are provided. With this exclusion, EPA concludes that devices such as thermal oxidizers, pollution control devices, fume incinerators, burnout furnaces, and other such equipment would report only GHG emissions from the firing of supplemental fossil fuels. This allowance is provided because we anticipate that the majority of GHG emissions released from thermal incinerators and similar control devices will be the result of fuel combustion because the organic content of the combusted streams are typically small.

If the refinery's fuel gas is used as fuel for the incinerator or other combustion device, then the Tier 3 method (e.g., Equation C-5 of subpart C in the final rule) must be used as specified in Subpart Y. We intend that the Tier 3 method will be used for fuel gas fired units, regardless of the fired capacity. However, the CO₂ emissions arising from the combustion of hydrocarbons in the process gas do not need to be assessed for these smaller combustion units (those less than 250 MMBtu/hr heat input capacities). We do not anticipate thermal control devices to have firing capacities greater than 250 MMBtu/hr, but if such a control system were used, then subpart C only requires accounting for the GHG emissions from unconventional fuels (such as process gas) if CEMS are used or if these "fuels" contribute 10 percent or more of the annual unit heat input to the unit.

As such, the process vent stream requirements in subpart Y primarily apply to streams vented without combustion. However, they do apply to streams combusted in units other than flares if the units are not required to report under subpart C (i.e., do not use supplemental fuel). In the unlikely event that these process streams are combusted in units that do not have to report under subpart C, the process vent stream provisions would apply. We also note that we have included concentration applicability thresholds (2% for CO₂; 0.5% for CH₄; and 0.01% for N₂O) for process vents to allow refinery owners and operators to focus reporting on the process vents that are expected to contribute most to the facility's GHG emissions. If the process vents have GHG concentrations exceeding these concentration thresholds and are not required to be reported elsewhere in subpart Y or in subpart C, then the GHG emissions

2. REPORTING THRESHOLD

Commenter Name: Renae Schmidt

Commenter Affiliation: CITGO Petroleum Corporation

Document Control Number: EPA-HQ-OAR-2008-0508-0726.1

Comment Excerpt Number: 17

Comment: CITGO believes that reporting thresholds should be established for source categories within a refinery. These thresholds could be based on total amounts of GHGs or a percentage of a refinery's total GHG emissions. CITGO agrees with the relative accuracy of the "Technical Support Document for Petroleum Refinery Sector: Proposed Rule for Mandatory Reporting of Greenhouse Gases" dated September 8, 2008. In this EPA sponsored document, EPA correctly identifies the largest GHG contributors as combustion sources and cat coke burning. These 2 categories alone account for 93% of the total GHG emissions. CITGO believes that the reporting rule should focus on these source categories in terms of quality control and reporting. Other potential sources such as sulfur plants, hydrogen plants and flaring account for another 6.2% of the total GHG emissions. CITGO is not opposed to reporting these emissions but is strongly opposed to excessive and unnecessary calculations associated with reporting for these sources. The remaining sources listed such as process vents, asphalt blowing, cooling tower, fugitive emissions, delayed coking, storage tanks, wastewater and blowdown account for only 0.8% of the total GHG emissions. These sources should be excluded from the reporting requirements because of their insignificant contribution. Because the focus on achieving GHG emission reductions will be focused on the large sources where greater reductions may be practically achieved, these insignificant sources will have no reasonable bearing on the eventual GHG management program or inventory tracking. To require such detailed monitoring, calculation, record keeping and reporting creates unnecessary burden costs and compliance liability. This unnecessary burden also can serve to diminish efforts to provide more accurate GHG emissions from the larger sources because of time and resources being "shifted" to smaller, meaningless source categories. As the rule is currently drafted, 70% or more of the overall program burden will be expended for less than 1% of the total GHG emissions. It is important to recognize that any GHG program or solution should focus on the significant GHG contributors. Including insignificant sources burdens both the refineries as well as other industries and results in excessive reporting, compliance management, and eventual program implementation. The phrase "Keep It Simple" needs to be applied for such a massive reporting undertaking. One only has to look across the fence at the IRS rules to understand the importance of this concept. It is important to start out with a manageable protocol that captures reliable and relevant information,

at the beginning of the process. This approach allows the program to be implemented at a practical and sustainable level.

Response: Please see Sections II.K and III.Y.3 of the preamble for responses to this comment. We also added a definition of process vent and added concentration thresholds for process vents in subpart Y to minimize the need to estimate GHG emissions from process vents that do not contain appreciable GHG content.

3. GHGS TO REPORT

Commenter Name: See Table 2

Commenter Affiliation:

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

Comment Excerpt Number: 184

Comment: §98.252(a). §98.252(a) notes “For each stationary combustion unit, you must follow [...] subpart C of this part.” This statement implies that reporting of combustion emissions for subpart Y must be performed on a unit-level basis. This is in contrast to the requirements of subpart C, which does not require unit-level reporting. Subpart C allows emissions to be reported on a unit-level, aggregate, common stack, or common pipe basis. The methodologies presented in subpart C, including the alternatives to unit-level reporting, are adequate for calculating emissions from combustion sources subject to Subpart Y. For this reason, it is recommended that the words “For each stationary combustion unit” be deleted from §98.252(a).

Response: EPA agrees with this comment. We have revised the text in §98.252(a) to state “for each stationary combustion unit or group of stationary combustion units” and we further specify that “You may aggregate units, monitor common stacks, or monitor common (fuel) pipes as provided in §98.36(c) when calculating and reporting emissions from stationary combustion units.”

Commenter Name: Renae Schmidt

Commenter Affiliation: CITGO Petroleum Corporation

Document Control Number: EPA-HQ-OAR-2008-0508-0726.1

Comment Excerpt Number: 27

Comment: It is CITGO's position that the reporting de minimis should be applied for any wastewater treatment facilities within a refinery. And certainly if the larger public wastewater treatment systems are excluded, the minimal industrial treatment systems do not belong in the rule.

Response: In regard to wastewater treatment, EPA is not going final with that source category at this time; please see Section III.II of the preamble and the relevant comment/response document.

Commenter Name: Renae Schmidt
Commenter Affiliation: CITGO Petroleum Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0726.1
Comment Excerpt Number: 26

Comment: It is CITGO's position that the reporting de minimis should be applied for any landfill within a refinery.

Response: In response to industrial landfills, EPA is not going final with that source category at this time; please see Section III.HH of the preamble and the relevant comment/response document. In regard to a de minimis provision, please see Sections II.K and III.Y.3 of the preamble.

Commenter Name: Renae Schmidt
Commenter Affiliation: CITGO Petroleum Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0726.1
Comment Excerpt Number: 19

Comment: CITGO does agree that the following process categories should be considered for reporting: 1. Combustion Sources 2. Cat Cracker Coking Burning 3. Hydrogen Plants 4. Sulfur Plants CITGO strongly believes that the following sources should be excluded from ongoing recalculation, monitoring and reporting: 1. Catalytic reforming units 2. Asphalt blowing 3. Fugitive emissions 4. Storage tanks 5. Loading operations 6. Delayed coking operations 7. Process vents below an establish threshold (at least 1% contributor to overall site GHG emissions) 8. Landfills 9. Wastewater treatment 10. Flares

Response: Please see Sections II.K and III.Y.3 of the preamble for responses to this comment. Also, in regard to industrial landfills, EPA is not going final with that source category at this time; please see Section III.HH of the preamble and the relevant comment/response document. Lastly, in regard to wastewater treatment, EPA is not going final at this time with that source category; please see Section III.II of the preamble and the relevant comment/response document.

Commenter Name: Renae Schmidt
Commenter Affiliation: CITGO Petroleum Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0726.1
Comment Excerpt Number: 18

Comment: As stated earlier, CITGO strongly disagrees with the mandatory reporting of CH₄ and N₂O within the Petroleum Refinery source category. As shown in the above named Technical Document, N₂O emissions account for 0.09% of the GHG emissions while CH₄ account for only 0.87% of the GHGs emissions. CITGO believes that the GHG reporting rule (for refineries) should be solely based on CO₂ emissions. It makes no sense to track, calculate, and report such insignificant contributors. Measurement error alone for the combustion sources and cat cracker coke burns significantly exceed the contributions of these sources! For example, orifice meters typically have 2-4% accuracy expectations depending on use and process conditions. Again, CITGO urges EPA to focus on significant GHG contributors. In almost all cases, reduction in CO₂ emissions will result in reduction of N₂O emissions. Also, most of the CH₄ emissions at a refinery are associated with either combustion inefficiency or sources that are

controlled under other regulatory air compliance programs that already achieve a high degree of control.

Response: Please see Sections II.K and III.Y.3 of the preamble for responses to this comment.

4. SELECTION OF PROPOSED GHG EMISSIONS CALCULATION AND MONITORING METHODS

Commenter Name: Dan F. Hunter

Commenter Affiliation: ConocoPhillips Company

Document Control Number: EPA-HQ-OAR-2008-0508-0515.1

Comment Excerpt Number: 8

Comment: The preamble has made reference to the work that the American Petroleum Institute (API) has done in measuring greenhouse gas emissions. API's efforts have resulted in the development and publication of several key guidance documents and tools to promote the consistent and accurate quantification and reporting of GHG emissions from oil and natural gas industry operations, and a framework for assessing GHG emission reductions from specific projects. These publicly available documents include: a) A compilation of applicable GHG estimation methodologies (API Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil & Gas Industry); b) Guidelines for reporting greenhouse gas emissions (API/IPIECA Petroleum Industry Greenhouse Gas Reporting Guideline); and c) A series of guidelines to assist the oil and natural gas industry in identifying, assessing, and developing candidate projects that would lead to credible emission reductions (GHG Project Guidelines). The API Compendium of GHG Emission Methodologies is widely used by the oil and gas industry. These guidelines and other existing protocols should be acceptable for this reporting rule. The calculations methodologies should allow for the use of the API Compendium. If a methodology is not available, a methodology identified in the applicable subpart should be used to calculate emissions.

Response: While we made an effort to include methods provided in the API Compendium and used by the petroleum refining industry, we also desired to have a comparable dataset across refineries. Consequently, we attempted to strike a balance between allowing any and all methods that have been presented in various other reporting rules and inventory guidelines and specifying a single method to be followed by all facilities. As proposed, we provide very simple alternative calculation methods for facilities to estimate emissions from smaller GHG emissions sources such as equipment leak and storage tanks. For flares, we allow "engineering estimates" when measurements are not performed. However, for larger GHG emission sources, we elected to minimize the number of alternative calculation methods to those we anticipate will provide the best estimate of GHG emissions. Thus, we believe the final rule strikes an appropriate balance by providing a limited range of calculation alternatives to give flexibility to the petroleum refinery owner or operator, while still providing comparability between reporting entities and limiting the overall uncertainty of the reported emissions.

Commenter Name: See Table 2

Commenter Affiliation:

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

Comment Excerpt Number: 179

Comment: EPA requests comment “on the engineering methods available to estimate coke burn-off rates, the uncertainty of the methods, and the measurements or parameters and enhanced QA that can be used to verify the engineering emission estimates and their certainty.” (p. 16541) API comments: EPA rule 40 CFR 63, Subpart UUU (April 2002) and EPA rule 40 CFR 60, Subpart Ja (July 2008) provide an approach to estimate the coke burn rate using the “K1, K2, K3” approach. [see DCN:EPA-HQ-OAR-2008-0508-0679.1 for equations for coke burn rate of exhaust gas before entering the emission control system, and subsequent CO₂ emission rate]. Although the EPA rule includes the use of all three “K” terms, CO₂ emissions can be estimated directly from the K1 term. With this knowledge, the carbon fraction (CF) can be determined by dividing the total carbon content in the coke by the total coke burned. [see DCN:EPA-HQ-OAR-2008-0508-0679.1 for detailed sequence of equations.] Therefore, by inspection, the CO₂ emissions can be estimated directly from the K1 term without introducing the error associated with K2 and K3 terms and the coke carbon fraction. As a result the measured parameters are limited to PCO₂ (the percent CO₂ concentration in regenerator exhaust), PCO (the percent CO concentration in regenerator exhaust), Qa (the volumetric flow rate of air to regenerator as determined from control room instrumentation, QOxy (the volumetric flow rate of O₂ enriched air to regenerator as determined from control room instrumentation, and PO₂ (the percent O₂ concentration in regenerator exhaust).

Response: The equation provided in the proposed and final rule for estimating CO₂ emissions from coke burn-off for catalytic cracking units is equivalent to the one derived by the commenter. We agree that there is no need to calculate the coke burn-off and then calculate carbon content of the coke to estimate the CO₂ emissions from this source. We also agree that the monitored CO₂ and CO concentrations provide the best method for estimating CO₂ emissions from this source.

Commenter Name: See Table 2

Commenter Affiliation:

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

Comment Excerpt Number: 177

Comment: “The Agency requests comment on the feasibility of allowing smaller emission sources at the refinery to employ less certain (Option 1) methods as a way to reduce the costs and burden of measurement and verification under this proposed rule.” (p. 16541) API comments: API supports the tailoring of emission estimation methods to fit the relative contribution of an emission source to the overall inventory.

Response: We believe the final rule contains very simple (less rigorous) methods (as were proposed) by which a refinery may elect to determine its GHG emissions from sources that are expected to be small contributors.

Commenter Name: Lorraine Krupa Gershman

Commenter Affiliation: American Chemistry Council (ACC)

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

Comment Excerpt Number: 132

Comment: Section 98.253 would require installation of additional CO, CO₂ and flow CEM systems to estimate emissions from catalytic cracking and catalytic reforming units. Many facilities have installed CEM systems and developed estimating methodologies for process optimization and for determining emissions (i.e. coke burned off, NO_x, SO_x) from those units. The reporting rule should provide the option for facilities to use alternate calculation by maximizing the use of existing systems, complemented, if necessary, with additional systems or procedures to estimate the GHG emissions.

Response: We do not require CO₂/CO/O₂ monitoring systems for catalytic reforming units (any size) or for catalytic cracking units with capacities of 10,000 bbls/day or less because these units are smaller GHG emission sources and are most likely to not have existing monitoring systems. For these sources, we allow engineering estimates as an alternative to the use of a CO₂/CO/O₂ monitoring system when a monitoring system is not already in-place. We note that all of the catalytic cracking units are subject to 40 CFR Part 63 subpart UUU, and nearly all of the compliance options for subpart UUU, especially those likely to be used for catalytic cracking units with capacities greater than 10,000 bbl/day, require CO/CO₂/O₂ gas monitors to determine coke burn-off rates. Therefore, we find that the monitoring requirements as provided in the final rule are reasonable for these processes.

Commenter Name: Dan F. Hunter

Commenter Affiliation: ConocoPhillips Company

Document Control Number: EPA-HQ-OAR-2008-0508-0515.1

Comment Excerpt Number: 55

Comment: The EPA requirements for flares are significant, especially for SSM. ConocoPhillips encourages EPA to reduce the SSM requirements for flares for this rulemaking. As EPA notes, flares make up only 1.6% of the total.

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

Commenter Name: Gary F. Lindgren

Commenter Affiliation: Calumet Specialty Products Partner, L.P.

Document Control Number: EPA-HQ-OAR-2008-0508-0626.1

Comment Excerpt Number: 14

Comment: Petroleum refineries should have the flexibility to utilize the appropriate methodologies outlined by the American Petroleum Institute in the documents entitled API Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil & Gas Industry and Equipment leaks should be by calculation, with no mandatory changes to existing LDAR programs to address methane. Modifying existing LDAR compliance programs alone can easily exceed the EPA's estimated annual costs of compliance for an average refinery.

Response: We do not require modifying existing LDAR programs to address methane. We simply provide that as an alternative to refineries that have that information readily available. We also provide a very simple method by which refineries can estimate and report their

equipment leak emissions. The API Compendium's method for equipment leaks assumes they are minimal and does not require reporting them. We would like to get more data on these sources to verify this conclusion.

Commenter Name: Deborah Seligman

Commenter Affiliation: New Mexico Oil and Gas Association (NMOGA)

Document Control Number: EPA-HQ-OAR-2008-0508-0603.1

Comment Excerpt Number: 11

Comment: EPA has underestimated the additional burden required to comply with the proposed quality assurance/quality control (QA/QC), recordkeeping, and reporting requirements for petroleum refineries. In the preamble for proposed 40 CFR 98 Subpart Y Section 1. "Definition of the Source Category", EPA states "All U.S. refineries must report their fuel consumption to the EIA, so there is limited additional burden to estimate their greenhouse gas emissions." (74 FR 16540). While it is correct that fuel consumption is reported, the proposed rule imposes additional QA/QC, recordkeeping, and reporting requirements that are not justified. The proposed rule would require a daily analysis of the fuel gas carbon content for most refineries. While the composition of the fuel may vary from day-to-day, the variations are typically not significant unless major operating changes have occurred. A weekly or monthly fuel gas analysis would be accurate enough for the purpose of estimating CO₂ emissions from fuel consumption. Simplifying the analysis, and allowing the use of appropriate fuel gas meter readings or estimates of refinery-wide fuel consumption, should provide GHG emission rate estimates with enough accuracy for global-scale modeling. The incremental difference in the precision of the estimate is not justified given the intended use of the data and the accuracy of the global climate models.

Response: We have clarified in subpart Y that central fuel gas monitoring is allowed. We have also reduced the minimum monitoring requirement for fuel gas to weekly in subpart C. When equipment are in-place to conduct daily monitoring, then daily monitoring is required; otherwise, weekly sampling is allowed. We determined that the reduction in uncertainty when sampling 365 times per year versus 52 samples a year was small and did not justify the additional sampling costs. However, the uncertainty reduction when sampling 52 times per year versus 12 times per year (monthly sampling) was significant. As such, we concluded that the appropriate minimum sampling frequency for flare gas in Subpart Y and, if the necessary equipment is not in place for daily monitoring, for fuel gas in subpart C, is weekly. With respect to the cost burden estimates, please see our response in Section III.Y.3 of the preamble.

Commenter Name: James S. Loving

Commenter Affiliation: National Cooperative Refinery Association (NCRA)

Document Control Number: EPA-HQ-OAR-2008-0508-0609.1

Comment Excerpt Number: 10

Comment: Focus GHG monitoring and reporting requirements on combustion and catalytic coke, which according to EPA cover 93% of emissions. Treat all other emissions as de minimis, with less frequent reporting through an alternative method and exempted from annual reporting unless major operating changes are made. For NCRA, GHG emissions for combustion and catalytic coke are calculated as totaling 96% of our total GHG emissions, based on a 2007 analysis for the Kansas Department of Health and Environment.

Response: Please see Sections II.K and III.Y.3 of the preamble for responses to this comment.

Commenter Name: John Bosch

Commenter Affiliation: BoschEnviron

Document Control Number: EPA-HQ-OAR-2008-0508-0212i

Comment Excerpt Number: 2

Comment: Lastly, my recent experience with essentially the petroleum industry, both upstream and downstream, has shown egregious huge losses that were not accounted for by these factors up to 10, sometimes up to 40 times the actual emissions or 40 times those which were estimated, and the only way we are getting a handle on it now is doing studies using these open-path fenceline techniques.

Response: The commenter is likely referring to recent Differential Adsorption LIDAR (DIAL) studies showing that certain emission sources, such as delayed coking units, revealed much larger emissions for certain pollutants than previously realized. While some sources, particularly fugitive sources and flares, do not lend themselves to traditional measurement techniques, the costs associated with open-path monitoring are significant, and this measurement technique has much greater uncertainty than the measurement methods required for the key GHG emission sources. Requiring open-path monitoring for these smaller sources is not justified for this rule.

Commenter Name: Matt Smorch

Commenter Affiliation: Countrymark Cooperative, LLP

Document Control Number: EPA-HQ-OAR-2008-0508-1081.1

Comment Excerpt Number: 9

Comment: We suggest that for the Sulfur Recover Unit (SRU) emissions the rule should be consistent with NSPS and exempt SRUs that are less than 20 long tons per day capacity. If this exemption is not provided, then hydrocarbons that enter the SRU via the amine system should be exempt. As a practical matter, an amine system will not operate properly with significant hydrocarbons, therefore, hydrocarbons in amines should be considered de minimus. Further, there is really no efficient way to measure hydrocarbons in an amine system on a consistent basis. The rule only provides for generic emissions factors to be used for fugitive emissions. Our refinery has a comprehensive Leak Detection and Repair (LDAR) program. The rule should allow for actual emissions results to be used for fugitive emissions. Using the generic factors will significantly over- state the emissions.

Response: We disagree that SRUs less than 20 long tons per day capacity should be excluded from reporting. This NSPS threshold was based on EPA's prior (and incorrect) analysis of the incremental cost of the tail gas treatment unit for small sulfur recovery plants, and we note that the new Refinery NSPS (40 CFR Part 60 Subpart Ja) includes requirements for these smaller SRUs. The cost of calculating and reporting the emissions from the SRU, given the default methods allowed, are minimal and do not pose a significant burden on the refinery owner or operator. Regarding the amine system, CO₂ is commonly collected and concentrated by the amine system. Other hydrocarbons have been identified in the sour gas stream as well. While the data are limited, we believe the carbon content (including CO₂) of the sour gas can be significant. Therefore, when carbon content is monitored, these data must be used in reporting

the GHG emissions from the sulfur recovery plant. If carbon content data are not available, the default parameter can be used.

The meaning of the comment regarding fugitive equipment leak emission estimates is unclear. If a refinery owner or operator has a comprehensive LDAR program that includes methane emission estimates for all sources for which appreciable methane is present, we specifically want these data reported. We are confident that detailed, component-specific LDAR measurement data can be used, in conjunction with stream composition data, to determine methane emissions from equipment leaks and that these methods are in accordance with the methods provided in the Equipment Leak Protocol Document. If monitoring of the fuel gas system is not performed, the default factors for equipment components based on facility-specific equipment counts can be used (as provided in the Equipment Leak Protocol Document). The very simple algorithm provided in the rule is only an alternative provided to minimize the burden associated with expanding an LDAR program to specifically include methane. We encourage refinery owners and operators to use the most detailed and accurate method for which they have data when reporting emissions from equipment leaks and other sources.

Commenter Name: See Table 2

Commenter Affiliation:

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

Comment Excerpt Number: 195

Comment: §98.253(g). Regarding the emission estimation approach for coke calcining, the aluminum industry is a user of calcined coke, not a producer. For this reason, the methodology developed by the aluminum industry should not be adopted as the industry standard for estimating CH₄ emissions. Actual operations indicate that the approach developed by IAI does not accurately estimate CH₄ emissions, and that site-specific adjustments are necessary. As such, CH₄ emissions should be calculated using best engineering practice.

Response: We assume the commenter is referring to CO₂ emissions from the coke calciner, not CH₄, as we have proposed a method for estimating CH₄ emissions that utilizes a default emission factor. The method provided for CO₂ is the best engineering practice for estimating emissions from the coke calciner that we identified. While the method was provided in a GHG protocol for the Aluminum Sector, it was specifically included “for those production facilities that have coke calcining operations...” Thus, some aluminum manufacturers also produce calcined coke. The method provided is generally applicable to coke calcining operations, regardless of whether those operations are conducted at a refinery or at an aluminum production facility. In fact, a refinery suggested this method for coke calciners for CARB’s Mandatory GHG Reporting rule. The current commenter did not provide specific recommendations as to what methods they consider to be “best engineering practice” nor what types of “site-specific adjustments” are needed or why they are needed. Consequently, we have made no changes in the requirements for coke calcining units.

Commenter Name: Sally V. Allen

Commenter Affiliation: Gary-Williams Energy Corporation

Document Control Number: EPA-HQ-OAR-2008-0508-0982.1

Comment Excerpt Number: 8

Comment: EPA should allow the use of engineering calculations for calculation of CO₂ emission rates for most refinery sources, including the catalytic cracking units and fluid coking units in refineries. Such calculations can provide more accurate data than Continuous Emissions Monitoring Systems (CEMS) if adequate process information, data on carbon content of materials and mass of materials processed or combusted are available. Flexibility in developing reporting methods and level of calculation details will be very important. Calculations can be more cost-effective and can be just as accurate. As we have noted above, the installation of CEMS involves high initial and ongoing costs and – therefore – CEMS are not appropriate for small GHG emission sources. Because data will ultimately be verified, there is no risk in allowing alternative calculation methodologies. If CEMS are required, there should be a cut-off size limit. For example, they should only be required for sources that are greater than 100mm Btu/hr (the standard break point for NO_x monitoring in Global Settlement Consent Decrees). In any case, there is no need for a dedicated CEMS for all refinery heaters if the fuel is the same for all heaters. One fuel gas CEMS and fuel gas meters on each heater would be much less expensive and provide the same data as individual CO₂ meters and flow meters on each stack.

Response: As discussed previously in response to comment EPA-HQ-OAR-2008-0508-0423.2, excerpt # 132 of this document, nearly all catalytic cracking units are required to have gas monitors in order to comply with 40 CFR part 63 subpart UUU. However, we do recognize that very small catalytic cracking units may not be required to have these monitors based on the alternative compliance options offered under subpart UUU (of 40 CFR part 63) for these smaller units. Consequently, for very small catalytic cracking units (10,000 bbl/stream day or less), we have allowed the use of engineering calculations as an alternative to installing gas monitors. We have also clarified in subpart C that CEMS are generally not required for combustion sources and that common (fuel) pipe monitoring can be used.

Commenter Name: Matt Smorch

Commenter Affiliation: Countrymark Cooperative, LLP

Document Control Number: EPA-HQ-OAR-2008-0508-1081.1

Comment Excerpt Number: 8

Comment: As we understand the rule, CO₂ CEMS would be required for the CCR platformer vent gas scrubber. Instead of requiring CEMS from being installed CO₂ emissions can be calculated using standard engineering practices based on laboratory analysis of coke on the catalyst.

Response: We did not require CO₂ CEMS for the catalytic reforming units. We effectively provided three options for catalytic reforming units (CEMS, CO/CO₂/O₂ monitor, or an engineering calculation), and we did not restrict the use of any option or place a hierarchy on when those options applied. We encourage facilities to use CEMS if CEMS are in-place, but we did not mandate their use because the quantity of coke burned in the reformer is typically quite small (in comparison to catalytic cracking and fluid coking units). The final rule also clarifies that engineering calculations can be used to estimate the coke burn-off emissions from the catalytic reforming unit.

Commenter Name: Matt Smorch

Commenter Affiliation: Countrymark Cooperative, LLP

Document Control Number: EPA-HQ-OAR-2008-0508-1081.1

Comment Excerpt Number: 7

Comment: In our understanding of the proposed regulation, Countrymark would need to have on-stream analysis of fuel gas and flare composition. Countrymark believes that composition of fuel gas can be estimated based on weekly fuel gas sampling since fuel gas is generally consistent. The rule should provide for estimating the emissions from flaring as flaring events are rare and instrumentation that would adequately and reliably measure these events would be difficult to design and cumbersome to maintain so the rule should allow for good engineering judgment to estimate the emissions from flare events.

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

Commenter Name: Lynn D. Westfall

Commenter Affiliation: Tesoro Corporation

Document Control Number: EPA-HQ-OAR-2008-0508-0669.1

Comment Excerpt Number: 1

Comment: As proposed in §98.253, facilities would be required to install additional CO, CO₂ and flow monitoring systems to estimate emissions from catalytic cracking and catalytic reforming units if they do not have existing CO₂ continuous emission monitoring systems already in place. Many facilities have existing CO and O₂ analyzer systems and have developed estimating reliable methodologies for process optimization and for determining emissions (i.e. coke burned off) from those units. The reporting rule should provide the option for facilities to use alternate calculation by maximizing the use of existing systems, complemented, if necessary, with additional engineering calculations or procedures to estimate the GHG emissions. Such provisions have been adopted in the mandatory GHG reporting regulation adopted by the California Air Resources Board (CARB). [footnote: See Instructional Guidance for Mandatory GHG Emissions Reporting (December 2008), pp. 10-9 to 10-11. The ARB guidance allows operators to determine the carbon content of fluidized catalytic cracking unit coke and accepts estimates based on periodic sample analysis and material balance-based determinations so long as they are "...well documented and supported.] We urge the EPA to take a similar approach and not require instrument-based data for all components of Equation Y-2 (74 Fed. Reg. at 16684).

Response: Please see Section III.Y.3 of the preamble for the response to this comment. Additionally, because catalytic reforming units do not produce nearly the quantity of coke as compared to the catalytic cracking unit, we did not intend to require CO₂ CEMS nor CO/CO₂/O₂ gas monitors for the catalytic reforming units. The final rule clarifies that engineering calculations can be used to estimate the coke burn-off emissions from the catalytic reforming unit when CO₂ CEMS or CO/CO₂/O₂ gas monitors are not in-place.

Commenter Name: Peter Boag

Commenter Affiliation: Canadian Petroleum Products Institute (CPPI)

Document Control Number: EPA-HQ-OAR-2008-0508-0428.1

Comment Excerpt Number: 6

Comment: A smarter approach for refineries. API methodologies are the industry backbone and regular scrutiny has proven their value. In particular, a) A compilation of applicable GHG estimation methodologies (API Compendium of Greenhouse Gas Emissions Estimation

Methodologies for the Oil & Gas Industry); b) Guidelines for reporting greenhouse gas emissions (API/IPIECA Petroleum Industry Greenhouse Gas Reporting Guideline). The API Compendium of GHG Emission Methodologies is widely used by the oil and gas industry. These guidelines and other existing protocols may all be acceptable for all reporting requirements across all jurisdictions who are proposing that the refining industry be subject to overlapping climate change strategies.

Response: Please see response to comment EPA-HQ-OAR-2008-0508-0515.1, Excerpt No. 8 of this document.

Commenter Name: Blair Wheeler

Commenter Affiliation: Aspen Technology, Inc.

Document Control Number: EPA-HQ-OAR-2008-0508-0488.2

Comment Excerpt Number: 4

Comment: In Subsection 7.3, Process Emissions a. Fluid Catalytic Cracking Unit (FCCU): we propose adding an additional option (Option 4) that would be based on direct measurement (minute or hour) and calculation of carbon emissions based upon operating conditions of the FCCU Reactor/Regenerator (i.e., pressure, flow, temperature, composition) utilizing a steady state engineering model specific to that process unit (calculates mass and energy balance). Please note that the composition of the FCCU feed (generally gas oil) is generally calculated on a refinery wide basis on a daily basis in the refinery planning LP (Linear Program) and available for use for this calculation. b. Catalytic Reforming Unit (CRU): we propose adding an additional option (Option 4) that would be based on direct measurement (minute or hour) and calculation of carbon emissions based upon operating conditions of the CRU Reactor/Regenerator (i.e., pressure, flow, temperature, composition) utilizing a steady state engineering model specific to that process unit (calculates mass and energy balance). Please note that the composition of the CRU feed (generally naphtha) is generally calculated on a refinery wide basis on a daily basis in the refinery planning LP (Linear Program) and available for use for this calculation. c. Fluid Coking Unit (FCU): we propose adding an additional option (Option 4) that would be based on direct measurement (minute or hour) and calculation of carbon emissions based upon operating conditions of the FCU Reactor/Regenerator (i.e., pressure, temperature, composition) utilizing a steady state engineering model specific to that process unit (calculates mass and energy balance). Please note that the composition of the FCU feed (generally gas oil or heavier) is generally calculated on a refinery wide basis on a daily basis in the refinery planning LP (Linear Program) and available for use for this calculation. d. Sulfur Recovery Unit (SRU): we propose adding an additional option (Option 4) that would be based on direct measurement (minute or hour) and calculation of carbon emissions based upon operating conditions of the Sour Water Stripper and SRU Claus Burner and Tail Gas Incinerator (i.e., pressure, temperature, composition) utilizing a steady state engineering model specific to that process unit.

Response: The commenter did not provide direct information regarding how the calculations would be performed; therefore, we could not assess the accuracy of the method nor could it be added as an option to the rule. For the catalytic cracking units and fluid coking units, we remain convinced that use of CEMS or CO/CO₂/O₂ monitoring data is the best approach. Engineering calculations are allowed for catalytic reforming units, sulfur recovery plants, and for catalytic cracking units with capacities of 10,000 bbls/day or less. Where engineering calculations are permitted, the approach described by the commenter may address the basic elements of what would be needed to perform engineering analyses.

Commenter Name: Blair Wheeler
Commenter Affiliation: Aspen Technology, Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0488.2
Comment Excerpt Number: 3

Comment: In Subsection 7.2, Flares, we propose adding an additional option (Option 4) that would be based on direct measurement (minute or hour) and calculation of carbon emissions based upon operating conditions of the process vessel venting to the flare (i.e., pressure, temperature, composition) utilizing a dynamic engineering model specific to that process unit and flare header system. Please note that the composition of the hydrocarbon in the vessel venting is generally calculated on a refinery wide basis on a daily basis in the refinery planning LP (Linear Program) and available for use for this flaring calculation.

Response: We remain convinced that fuel measurements in the flare gas header provide the best estimate of flare emissions. For flares that do not have monitoring data, engineering calculations are allowed. Where engineering calculations are permitted, the approach described by the commenter may address the basic elements of what would be needed to quantify these events for an engineering analysis. However, the commenter provided no direct information regarding how the calculations would be performed. Therefore, we could not assess the accuracy of the method nor could it be added as an option in the rule.

Commenter Name: Matt Smorch
Commenter Affiliation: Countrymark Cooperative, LLP
Document Control Number: EPA-HQ-OAR-2008-0508-1081.1
Comment Excerpt Number: 10

Comment: The proposed rule provides that emissions will need to be reported on a process by process basis and this will be overly cumbersome, time consuming, and expensive. Countrymark proposes that the rule should allow refiners to submit emissions on an aggregate basis.

Response: We have clarified the rule to allow aggregation of stationary combustion sources consistent with subpart C. Equipment leaks and storage tank emissions (except unstabilized crude oil) are also reported on an aggregate level. However, there are some process emissions that are desired on a unit-specific basis to provide additional policy analysis options or to allow verification of reported emissions.

Commenter Name: Rich Raiders
Commenter Affiliation: Arkema Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0511.1
Comment Excerpt Number: 45

Comment: Facilities that operate process flares to remove organic compounds from vapor streams usually must comply with existing flare management practices at either 40 CFR 60.18 or 40 CFR 63.11. These effectively identical requirements mandate owners and operators to maintain a minimum BTU content of the combusted flare vent stream. Most facilities comply with this provision by using a BTU analyzer to evaluate the vent stream en route to each process

flare. Facilities then combine this periodic BTU information and, in combination with process knowledge of what streams were vented to the flare headers system, calculate emissions of regulated air pollutants from the flare system. Likewise, owners and operators of gas-assisted or gas-piloted flares calculate natural gas products of combustion emissions based on metered flare gas flows. EPA should provide a section of Subpart B to document flare management practices for the various subparts regulating flare use. EPA should provide an opportunity for flare operators to substitute process knowledge of flare streams for the Tier 3 daily molecular weight and carbon content measurement requirements currently in proposed Subpart C. Measuring flare gas composition is unnecessary when the facility can document the flare vent streams. Operators of any flare that must report GHG emissions should have the option of determining flare GHG emissions by the procedure proposed at § 98.253(b) of Subpart Y. Because this procedure could apply not only to refinery fuel gas, but to any processing stream suitable for flaring, relying on existing BTU analyzers and flow meters, plus a gas meter for the natural gas pilot gas and/or maintenance gas, is an appropriate method to determine flare GHG emissions. The proposed 60 kg CO₂/mmBTU (HHV) emission factor is appropriate for use for any emission stream appropriately routed to a flare. EPA should further clarify that the appropriate equation for reporters to use for reporting flare GHG emissions is Equation C-2a, which includes the measured HHV, fuel flow rate, and 60 kg CO₂/mmBTU (HHV) emission factor described above. EPA should note in the response to comment concerning any final GHG reporting regulation that reporters calculating flare GHG emissions do not need to comply with Tier 3 or 4 requirements, unless the owner or operator elects to install and maintain the appropriate equipment. This proposal conforms to existing flare practices in many facilities that will be subject to reporting under Part 98, where periodic or online BTU analyzers are common, flare header flow meters are commonplace, and process knowledge exists to correlate emissions being routed from the related process unit(s) to the flare header. To encourage facilities to report using this proposed flare management system, and to eliminate confusion concerning how to report flare GHG emissions, EPA should relocate this provision into the general conditions Subpart B or the fuel combustion Subpart C, and refer to the requirements from each subpart that includes sources likely to be controlled by flares.

Response: The BTU (i.e., higher heating value) monitoring approach recommended by the commenter is consistent with EPA's proposed approach for flare monitoring under subpart Y. On the matter of relocating this provision to the general provisions, subpart B or subpart C, we have decided that since flares are not universally covered in the rule, it would not be appropriate to move it to another subpart. EPA has clarified in the preamble (for subpart C) that flares are not considered stationary combustion units and are not subject to reporting under subpart C. As such, the monitoring and reporting requirements for flares are appropriately included in the final subpart Y rule.

Commenter Name: Gregory A. Wilkins

Commenter Affiliation: Marathon Oil Corporation

Document Control Number: EPA-HQ-OAR-2008-0508-0712.1

Comment Excerpt Number: 81

Comment: Marathon supports EPA using the API Compendium to develop the methodologies for this subpart. As previously stated, this document is widely used and has sound reasoning and expertise behind the stated methodologies. Marathon supports EPA reviewing and using this document when preparing methodologies for this rule.

Response: Please see response to comment EPA-HQ-OAR-2008-0508-0515.1, Excerpt No. 8 of this document.

Commenter Name: Gregory A. Wilkins

Commenter Affiliation: Marathon Oil Corporation

Document Control Number: EPA-HQ-OAR-2008-0508-0712.1

Comment Excerpt Number: 80

Comment: For emissions from Fluid Catalytic Cracking Units (FCCUs), EPA proposes to use the methods for combustion to estimate CH₄ and N₂O emissions from FCCUs. However, the proposed 2009 revisions to the API Compendium states that CH₄ emissions are negligible (Chapter 5, Catalytic Cracking Regenerator Section). This is because that due to the high temperature, there would be little CH₄ emissions generated. Simply using combustion factors does not appear justified. While CH₄ and N₂O emissions can be present in the FCC, they are so small they are virtually undetectable. Marathon proposes the removal of the requirement to estimate emissions from CH₄ and N₂O from FCCUs because these emissions are present in insignificant amounts.

Response: We find no evidence that the combustion conditions of coke in the FCCU are significantly different that the combustion of petroleum coke in boilers or other furnaces from which the CH₄ and N₂O emission factors were developed. Although we agree that these are currently believed to be small contributors to the overall emissions calculations, their calculation is simple and does not require appreciable effort to include.

Commenter Name: Gregory A. Wilkins

Commenter Affiliation: Marathon Oil Corporation

Document Control Number: EPA-HQ-OAR-2008-0508-0712.1

Comment Excerpt Number: 79

Comment: The proposed 2009 revisions to the API Compendium state that there are several varieties of cokers in use in refineries, including delayed cokers and flexi-cokers and that no quantitative data have been found to estimate CH₄ emissions from these sources (Chapter 5, section on Cokers). Marathon operates only delayed coking units. EPA shows on the technical support document (as stated above) that delayed cokers only account for 0.058% of a facility's total emissions. Additionally, the vast majority of corer emissions should be from when the unit is depressurized to flare and those emissions would be estimated according to the flare calculation requirements. Marathon proposes that because these emissions are insignificant, that they be considered for use in the de minimis threshold.

Response: Recent test data for delayed coking units suggests that delayed coking units may be a more significant emission source than previously recognized, even when much of the depressurization gas is discharged to the flare. We agree that the discharge of gases to the flare are not to be included in the emissions from the delayed coking unit, but remain convinced that better GHG emission estimates are needed for delayed coking units. Please also see Sections II.K and III.Y.3 of the preamble for further response to this comment.

Commenter Name: Gregory A. Wilkins
Commenter Affiliation: Marathon Oil Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0712.1
Comment Excerpt Number: 77

Comment: Marathon supports allowing emissions from process vents to be estimated using process knowledge or measurement. Because these streams are very small and insignificant they should not have to be sampled or require direct measurement.

Response: We see no disagreement with EPA's proposed approach and thank the commenter for the comment.

Commenter Name: Gregory A. Wilkins
Commenter Affiliation: Marathon Oil Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0712.1
Comment Excerpt Number: 76

Comment: Marathon supports allowing the use of a simpler method for estimating emissions from catalytic reforming units and for the possibility of including them in the de minimis determination due to their small contribution to overall emissions from refineries. Marathon opposes the use of CEMs because of the high cost to monitor an insignificant source of emissions. Additionally, although the reporting rule requires emissions to be calculated for CH₄ and N₇₀, Marathon does not expect these emissions to be present, and the proposed 2009 revisions to the API Compendium do not include the estimation of these GI-IGs. If emissions estimation is required for reformers, Marathon would support an allowance for mass balance as opposed to CEMs.

Response: Please see Sections II.K and III.Y.3 of the preamble for responses to this comment.

Commenter Name: Gregory A. Wilkins
Commenter Affiliation: Marathon Oil Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0712.1
Comment Excerpt Number: 75

Comment: The proposed 2009 revisions to the API Compendium state that weathered crude oil and refinery products contain no CO₂ or CH₄ (Chapter 5, Tanks Working/Standing Losses). Therefore as Marathon's refineries store only weathered crude and refinery products, Marathon supports assuming emissions from tanks and loading losses at Petroleum Refineries to be zero unless the site has data to indicate otherwise. If a facility stores unweathered or unflashed crude, they would estimate emissions according to the methods in the Compendium.

Response: The default molecular weight and vapor pressure of crude oil (RVP-5) in the TANKS model default does not preclude the presence of methane. In fact, it is quite likely that small quantities of methane may remain in the crude oil and, given the large quantities of crude oil processed, yield direct methane emissions. While our engineering calculations support the idea that these emissions are potentially negligible, we seek additional data to confirm this assumption, preferably based on methane vapor space concentration data. However, we are not requiring detailed storage tank emission calculations and have provided a very simple emission

calculation methodology commensurate with the contribution these sources likely make to the refinery's GHG emissions.

Commenter Name: Gregory A. Wilkins

Commenter Affiliation: Marathon Oil Corporation

Document Control Number: EPA-HQ-OAR-2008-0508-0712.1

Comment Excerpt Number: 74

Comment: Equipment leak emissions would not be a source of CO₂ or N₂O. CH₄ emissions from refinery fugitives would only occur from fuel gas and natural gas systems or a few light end processing units. As shown above, EPA's study concluded that these emissions make up only .014% of the total emissions from a facility. In addition, the API Compendium states that refinery" fugitive emissions will generally have an insignificant contribution to the total GAG inventory because most refinery streams contain only small amounts of CI-14 (Chapter 6). If emissions from fugitives are required to be estimated, factors or engineering estimates should be allowed to be used for leaks including those listed in the API Compendium, as opposed to being prescriptive and allowing only EPA's "Protocol for Equipment Leak Emissions Estimates."

Response: The final rule (as was proposed) only requires calculation and reporting of CH₄ emissions from equipment leaks; we do not require calculation and reporting of CO₂ or N₂O emissions from equipment leaks. We do not require only methods in EPA's "Protocol for Equipment Leak Emissions Estimates." The proposed and final rules both allow a very simple process unit average emission factor approach. The API Compendium method for equipment leaks includes both a facility- and process-average emission factor approach. The facility average emission factor for refineries is provided in terms of total hydrocarbon (THC) emissions per barrel of throughput. However, no real guidance is provided on how to determine the ratio of methane to THC emissions in order to calculate the methane emissions from this factor. Moreover, as recognized by the Compendium, emissions from equipment leaks are more a function of the number of equipment components rather than processing rate. The API Compendium also provides a process-average emission factor method. However, the processes for which factors are provided in the Compendium are for crude production, gas processing, and gas distribution; no process emission factors are provided for petroleum refining processes. The simplified method for equipment leaks provided in the rule utilizes this average process unit emission factor approach, but provides default emission factors to the key refinery process units. Thus, the method allowed in the rule is consistent with the process-average approach suggested in the API Compendium and provides necessary default values so refineries can easily use this method.

Commenter Name: Gregory A. Wilkins

Commenter Affiliation: Marathon Oil Corporation

Document Control Number: EPA-HQ-OAR-2008-0508-0712.1

Comment Excerpt Number: 67

Comment: Marathon supports the use of engineering estimates and default factors instead of requiring direct measurement (CEMs) to calculate emissions from flares during periods of routine and episodic flaring.

Response: When flare gas flow and composition monitors are in-place, we require their use for estimating emissions from flares. However, as proposed, we are not requiring the installation of these monitoring systems and have retained the option for using engineering estimates and default factors to calculate emissions from flares during periods of routine and episodic flaring in the final rule.

Commenter Name: See Table 2

Commenter Affiliation:

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

Comment Excerpt Number: 181

Comment: 79. Preamble, p. 16541. EPA notes that “The selected monitoring methods for this proposed rule generally follow those used in other reporting rules as well as those recommended in the 80. American Petroleum Institute’s Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry.” (p. 16541) API comments: API greatly appreciates the inclusion of the API Compendium, however industry's review of the proposed rule has indicated some inconsistencies. Key examples of differences and deviations from the API Compendium, which are elaborated throughout these comments, include methods related to the following: fugitive emissions, flares, oil/water separators, wastewater treatment, glycol dehydrators, acid gas removal, tank flashing emissions, FCCUs, asphalt blowing, coke drums, equipment blowdowns, pneumatic devices, chemical injection pumps, and non-routine activities.

Response: Please see response to comment EPA-HQ-OAR-2008-0508-0515.1, Excerpt No. 8 of this document.

Commenter Name: Rich Raiders

Commenter Affiliation: Arkema Inc.

Document Control Number: EPA-HQ-OAR-2008-0508-0511.1

Comment Excerpt Number: 46

Comment: 40 CFR 60.18 and 63.11 requires annual verification of the BTU analysis of the flare vent stream for each regulated flare. Compliance with this reporting system should be adequate to demonstrate compliance with these existing flare management requirements. EPA should either amend 40 CFR 60.18(b)(6) and 40 CFR 63.1 1(b)(6) to note that compliance with the provisions of this part meets the BTU analysis requirements of the Part 60 or 63, or include a provision in this subpart that compliance with this BTU measurement system meets the BTU analysis requirements of 40 CFR 60.1 8(b)(6) or 40 CFR 63.11 (b)(6).

Response: We have reviewed the requirements of 40 CFR 60.1 8(b)(6) or 40 CFR 63.11 (b)(6) and do not see a specific requirement for annual verification of the BTU analysis. We do note that we allow the same methods that are provided in these sections, except for ASTM D2382 which was withdrawn in 1994 and replaced by ASTM D4809. However, we cannot state that compliance with 40 CFR 60.18(b)(6) and 40 CFR 63.1 1(b)(6) is compliant with subpart Y. It is beyond the scope of this rulemaking to amend Parts 60 and 63.

Commenter Name: See Table 2

Commenter Affiliation:

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

Comment Excerpt Number: 188

Comment: §98.253(b). Refinery flares emit a small percent of refinery CO₂e emissions, yet under the proposed rule have extensive reporting requirements. Instead of detailed calculation approaches, flare emissions should allow any of the following: 1) include as a de minimis source type and exempt from annual reporting; 2) include using a one-time calculation to demonstrate annual compliance; 3) exempt from reporting requirements if equipped with a flare gas recovery system.

Response: Flares are of specific interest from the standpoint of policy analysis. While flares are currently believed to be a small source of GHG emissions in comparison to other sources at refineries, they are not a trivial source. Additionally, flaring reduction has a number of potential benefits, especially if the flare gas can be recovered and used as fuel, increasing the overall energy efficiency of the plant. Also, flare use can vary significantly from day-to-day and year-to-year. EPA needs accurate data on flare emissions to better understand this emission source. Please also see Sections II.K and III.Y.3 of the preamble for further response to this comment.

Commenter Name: Sam Chamberlain

Commenter Affiliation: Murphy Oil Corporation

Document Control Number: EPA-HQ-OAR-2008-0508-0625

Comment Excerpt Number: 37

Comment: The EPA requires reporting of CO₂ & CH₄ covered under sub-part II; Refinery Rule page 16683. Three wastewater measurement options are provided by EPA: Modeling vs. Direct Measurement vs. Activity Data. For CO₂ from OW Separators, measure volume of wastewater weekly, multiply by the non-methane VOC organic carbon emission factor for the type of separator used. (EPA DEFAULT IS NMVOC=0.6). EPA's equation II-2 rule page 16705 provides additional guidance. We have no anaerobic digester, or anaerobic wastewater system. As a Refinery, we only report CO₂ for oil/water separators per the preamble language page 16561. Murphy supports the EPA options provided. Murphy has only one API separator that uses fuel gas (purge gas under the roof) and Murphy will apply the appropriate emission factor provided by EPA.

Response: In regard to wastewater treatment, EPA is not going final with that source category at this time; please see Section III.II of the preamble and the relevant comment/response document.

Commenter Name: Sam Chamberlain

Commenter Affiliation: Murphy Oil Corporation

Document Control Number: EPA-HQ-OAR-2008-0508-0625

Comment Excerpt Number: 36

Comment: EPA requires reporting of CO₂ emissions from Sulfur Recover Plants, both on-site and off-site. EPA requires emissions determination as follows: Sour gas stream flow: If a

continuous flow meter is in place must be used or you may use engineering calculations or company records for volumetric flow rates. For carbon content, if measured then measurement device must be used or develop a site specific carbon content factor or use EPA default value of .20. We may use CEMS on final exhaust stack of SRU if in place. We must monitor fuel use in Claus Burner, tail gas incinerator, or other combustion sources that discharge via stack. NOTE: Process emissions calculated as delta between CO₂ CEMS & calculated combustion emissions (Page 16685, last paragraph) which can be problematic. Murphy's refineries have looked at this closely and are trying to devise an accounting system to avoid double accounting of CO₂ Emissions for the Amine System -see page 16539 in rules and to account for CO₂ calculations in fuel gas. Regarding the subtraction, Murphy understands that the rule requires the reporting of combustion emissions associated with the SRU (e.g. from the Claus burner) separately from the process emissions - under Subpart C instead of Subpart Y. Murphy does have combustion sources venting to the same stack as its SRU and thus will monitor fuel use as it does not have a CEMS on its SRU. We will monitor this closely to avoid double accounting of CO₂ Emissions for the Amine System.

Response: We see no disagreement with EPA's proposed approach and thank the commenter for the comment.

Commenter Name: See Table 1

Commenter Affiliation:

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

Comment Excerpt Number: 29

Comment: NPRA disagrees with the reporting for CH₄ and N₂O within the combustion sources and some petroleum refinery source categories. Rather, greenhouse gases resulting from combustion sources or processes should be reported on a CO₂e basis rather than CO₂, N₂O, and CH₄ separately. CH₄ and N₂O greenhouse gas contributors are insignificant when compared to the CO₂ emissions and, as such, should be combined into a single emission factor for calculating and reporting purposes. As an example, the default factor for natural gas is 102.04 while the default values for CH₄ and N₂O are 9.0 x 10⁻⁴ and 1.0 x 10⁻⁴, respectively. If one then applies the global warming potential, the CO₂e equivalent can be shown. [See DCN:EPA-HQ-OAR-2008-0508-0433.2 for data table showing CO₂, CH₄, and N₂O contributions to combustion CO₂e from natural gas combustion.]. Similar calculations apply to other fuels used within a refinery. In summary, NPRA believes that greenhouse gas emission reporting should be on CO₂e basis for all combustion sources including cat cracker coke combustion. It makes little sense to track, calculate, and report these greenhouse gases separately. Measurement error alone for the combustion sources and cat cracker coke burns significantly exceed the contributions of either CH₄ or N₂O combustion. For example, orifice meters typically have 1% - 3% accuracy, depending on use and process conditions – well above the CH₄ and N₂O contribution. For complex refineries with dozens of combustion sources, setting up and verifying additional (and unnecessary) calculations in a database or spreadsheet is time consuming and expensive. In addition, these extra calculations steps can often result in error due to extra configuration of a database or spreadsheet. NPRA urges EPA to keep reporting as simple as possible and focus on calculation and measurement accuracy not insignificant contribution breakout of CH₄ and N₂O.

Response: See our response in Section III.Y.3 of the preamble. In regard to reporting individual gases as opposed to carbon dioxide equivalent only, please see Section II.I of the preamble.

Commenter Name: See Table 1

Commenter Affiliation:

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

Comment Excerpt Number: 26

Comment: GHG annual emissions from flares represent a relatively small fraction of the total GHG emissions from a typical refinery (EPA estimates this at 1.6 percent). Annual emissions include those generated during normal operations (i.e., sweep gas, pilot gas, leaks) and those generated during Startup, Shutdown and Malfunction (S SM) events. Moreover, flare emissions have been and will continue to be reduced as a result of regulatory and/or enforcement actions by federal, state and local regulatory agencies. Therefore, it is unreasonable to impose onerous monitoring, QA/QC, reporting and recordkeeping requirements, in addition to the risks associated with daily sampling of flare gases, for these relatively insignificant sources of GHG emissions. We recommend the following: 1. Flare GHG emissions should be listed as de minimis emissions and exempted from annual reporting, or reported at the discretion of each company. 2. NPRA recommends a one-time calculation for normal events (with an estimate of emissions from extraordinary flaring events using engineering calculations) 3. If EPA disagrees with the one-time calculation, NPRA recommends that all GHG emissions determinations be done using engineering calculations as required by many consent decrees. 4. Facilities that are equipped with flare gas recovery systems should be exempt from Subpart Y. As proposed in §98.253, facilities would be required to install additional CO, CO₂ and flow monitoring systems to estimate emissions from catalytic cracking and catalytic reforming units. Many facilities have installed analyzer systems and have developed estimating methodologies for process optimization and for determining emissions (i.e., coke burned off, NO_x, SO_x) from these units. The reporting rule should provide the option for facilities to use alternate calculations by maximizing the use of existing systems complemented, if necessary, with additional systems or procedures to estimate the GHG emissions.

Response: Please see our response in Section III.Y.3 of the preamble and response to comment EPA-HQ-OAR-2008-0508-0679.1, Excerpt No. 188 of this document. Regarding flare gas recovery systems, we desire data from facilities with flare gas recovery systems to better assess the potential emission reductions that can be achieved. As we understand, most flare gas recovery systems are designed to recover typical loads with some excess recovery capacity, but do not recover flare gas released as a result of a sudden, large release, such as those caused by upsets or emergency shutdowns. Without data from flares with gas recovery systems, we cannot accurately assess the emission reductions from such a system.

Commenter Name: Sam Chamberlain

Commenter Affiliation: Murphy Oil Corporation

Document Control Number: EPA-HQ-OAR-2008-0508-0625

Comment Excerpt Number: 23

Comment: This reporting rule should not impose any new measurement requirements, or mandate installation of new instrumentation, including for example: new Leak Detection and Repair (LDAR) programs; use of Hi-flow samplers and component ‘bagging’; installation of new channels on existing CEMS; carbon content analysis; storage tank head space analysis; flare velocity metering; and fuel combustion metering. Such an approach would clearly exceed the

authority of the underlying legislation and has not been previously used for data collections under the authority of Section 114 of the CAA. The rule should allow reporters to utilize their best existing data, without mandating capital expenditures prior to the promulgation of a final regulatory framework.

Response: We do not interpret the new measurement requirements in the final rule as exceeding the authority of CAA Section 114. We have been judicious in where we require new equipment. Only the largest sources (stationary combustion units, catalytic cracking units, and fluid coking units) are required to collect a requisite number of samples or use a continuous monitoring system. Most of these sources are expected to already have these monitors in-place (e.g., catalytic cracking units complying with 40 CFR part 63 subpart UUU). For smaller sources of GHG emissions, we provide default methods or engineering calculations where appropriate to avoid installation of additional monitors. We specifically note that we do not require new LDAR programs, use of Hi-flow samplers, component “bagging”, or flare velocity metering. While carbon content or heat content analysis and fuel flow metering are generally required for combustion sources, these analysis and metering systems are generally in-place at the refinery. We did clarify in subpart Y that stationary combustion units at petroleum refineries can use common-pipe monitoring. We have revised our impacts based on the comments received and the final rule requirements and concluded that the burden associated with the final rule requirements is justified. (Please see Section III.Y.3 of the preamble for additional details.) For further discussion regarding the legal authority for this reporting rule, see the Response to Comments for Legal Issues.

Commenter Name: See Table 2

Commenter Affiliation:

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

Comment Excerpt Number: 203

Comment: §98.253(1). When estimating emissions from equipment leaks with component level emission factors, only emission factors provided in the Protocol for Equipment Leak Emissions Estimates can be used. This disregards emission factors developed by other organizations and studies. As noted above, the contribution of fugitive emissions to a refinery's overall GHG inventory support the use of alternative and less detailed emission estimation methods.

Response: In our review of the API Compendium and other sources, we did not find an appropriate simplified method for estimating equipment-specific leak emissions. The API Compendium includes both a facility- and process-average emission factor approach. The facility average emission factor for refineries is provided in terms of total hydrocarbon (THC) emissions per barrel of throughput. However, no guidance is provided on how to determine the ratio of methane to THC emissions in order to calculate the methane emissions from this facility average emission factor. Moreover, as recognized by the Compendium, emissions from equipment leaks are more a function of the number of equipment components rather than processing rate. The API Compendium also provides a process-average emission factor method. However, the processes for which factors are provided in the Compendium are for crude production, gas processing, and gas distribution; no process emission factors are provided for petroleum refining processes. The simplified method for equipment leaks provided in the rule utilizes this average process unit emission factor approach, but provides default emission factors to the key refinery process units. Thus, the method allowed in the rule is consistent with the process-average approach suggested in the API Compendium and provides necessary default

values so refineries can easily use this method. The commenter provided no direct suggestions regarding alternative methods to use.

Commenter Name: See Table 2

Commenter Affiliation:

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

Comment Excerpt Number: 202

Comment: §98.253(1). Equipment-level emissions from equipment leaks can only be estimated using EPA's Protocol for Equipment Leak Emission Estimates or the EPA derived equation, which applies CH₄ concentrations for refinery process units which are not cited or otherwise referenced (Table A-4. Estimated Methane Concentration and Fugitive Emission Rates for Model Refinery Process Units. EPA, Technical Support Document for the Petroleum Refining Sector: Proposed Rule for Mandatory Reporting of Greenhouse Gases, 2008.) API conducted a study to quantitatively assess the contribution of fugitive CH₄ emissions from equipment leaks to overall refinery GHG emissions. Emissions were estimated based on component counts in natural gas and refinery fuel gas service, using average emission factors for components in gas service provided by EPA (EPA, 1995). Fugitive CH₄ emissions were calculated for two refineries: 1. A smaller fuels refinery with a rated capacity between 50,000 and 90,000 bbl feed/day; and 2. A larger refinery/petrochemical complex with a rated capacity between 100,000 and 199,000 bbl feed/day. Results indicated that CH₄ emissions from equipment leaks represent 0.11% of total GHG emissions for the smaller refinery and 0.19% of total emissions for the large refinery. Since other large GHG emitting sources have uncertainties within the range of 1% to 5% of the overall GHG inventory, a CH₄ fugitive emission contribution of 0.1% appears to be negligible. A summary report on the study is provided in Appendix F of the Compendium. These results justify being de minimis, using simplified emission estimates or best engineering calculations.

Response: Please see response to comment EPA-HQ-OAR-2008-0508-0625, Excerpt No. 38. Also, the simplified method for estimating emissions from equipment leaks in the final rule is documented in the Technical Support Document (TSD). The concentrations as provided in the TSD were estimated based on engineering estimates and are expected to be reasonable estimates of methane concentration. As noted previously, we have limited compositional data for methane in these streams as methane is not considered a VOC. We note that our estimates of the relative importance of methane from equipment leaks, as provided in the TSD, is much lower than those indicated by the commenter, suggesting that either the concentration profile or the leak frequency (or both) are underestimated. It is precisely the lack of sufficient data on methane that justifies the requirement for reporting methane emissions from equipment leaks. Furthermore, when direct equipment leak monitoring data are not available, the inclusion of the simplified equation provides respondents an easy method to estimate these emissions that is commensurate with the expected magnitude of emissions. In regard to a de minimis provision, please see Sections II.K and III.Y.3 of the preamble.

Commenter Name: Karen St. John

Commenter Affiliation: BP America Inc. (BP)

Document Control Number: EPA-HQ-OAR-2008-0508-0631.1

Comment Excerpt Number: 99

Comment: EPA has requested comment on the use of de minimis reporting to address small emission sources as a way to reduce cost and burden. BP supports the use of “simplified calculation methods” to address relatively small emission sources in the facility emission inventory. BP supports the use of a 5% de minimis reporting limit, similar to the de minimis methodology employed in the General Reporting Protocol of the California Climate Action Registry (CCAR) and other GHG registries. Under this method, a reporting facility may estimate emissions for these de minimis sources using alternative methods of the operator’s choosing, with the condition that these methods provides reasonable assurance of accuracy and that the emissions so designated and estimated do not exceed 5% of the total facility emissions. It is not cost effective to spend large amounts of time and resources to monitor and calculate a very small fraction of refinery emissions. EPA should not include an additional quantitative limit (i.e., less than 25,000 te) to the use of de minimis reporting. This would unfairly disadvantage large refineries where 25,000 te would be far less than 1% of total GHG emissions. A quantitative limit on the use of de minimis reporting would severely limit the ability of large refineries to capture the same inconsequential sources under de minimis reporting as a small refinery. The rationale of allowing the use of de minimis methods for up to 5% of the total reported facility emissions goes beyond the cost associated with measurement and verification. QA/QC, reporting, and monitoring requirements should also be relaxed for insignificant emission sources. The provision should allow a simplified method or limited studies to demonstrate de minimis. Sources determined to be inconsequential would also not have to comply with QA/QC, reporting, and monitoring requirements. The sources could be revisited every few years to confirm that the methods are still applicable. Some potential de minimis GHG emission sources for refineries include: fugitive emissions, tanks, wastewater treatment, oil water separators, sulfur recovery units, flaring, miscellaneous process vents and analyzer vents, loading losses, vapor recovery units, and reformers for refineries. These sources represent a small fraction of total refinery GHG emissions but would require the same laborious monitoring and reporting requires of large significant source. De minimis reporting would allow for the appropriate prioritization for effort and resource. The API Compendium notes the following non-GHG sources which may be present at refineries: Cooling Towers; Equipment Leaks from liquid process streams; Product Tanks (e.g. gasoline tanks); Oil/Water Separators; and Process Drains. Marketing terminals may also be sources of VOC emissions (such as from equipment leaks and storage tanks), but not sources of GHG emissions. API members have concluded that there are no GHG emissions from these sources, and therefore they should not be included in a GHG inventory. In EPA's "Technical Support Document for the Petroleum Refining Sector: Proposed Rule for Mandatory Reporting of Greenhouse Gases", it shows on page 12 that...Asphalt Blowing, Delayed Coking, Equipment Leaks, Storage Tanks, Wastewater Treatment, and other sources are equal to less than 0.8% of a total refineries GHG emissions. In addition the pie chart shows flaring to be 1.6% of emissions from a refinery which industry believes is an over-estimate. Also the Sulfur Plant is shown on the graph to contribute roughly 1.9% of overall GHG emissions. Adding these insignificant sources together indicates that they represent only 4.3% of total refinery emissions yet require a large portion of the work to estimate emissions. API estimates that having a de minimis threshold of 5%, could reduce the compliance cost and labor burden by 50%. Of particular concern is the requirement for refineries to report GHG emissions from wastewater treatment. It is not enough to address wastewater as a de minimis source; it should be removed as a required source for refineries and petrochemical production. As stated above, the EPA Technical Support Document for Petroleum Refining reveals that CO₂e emissions from wastewater treatment facilities co-located at petroleum refineries account for only 0.43 % of the petroleum refining sector’s aggregate CO₂e. The calculation methodology and QA/QC procedures included in Subpart II are particularly complex and burdensome when applied to the complex (but very low emitting) wastewater systems at petroleum refinery. A

similar conclusion is reached when analyzing the petrochemical production sector. BP does not believe that the burden of monitoring, QA/QC, recordkeeping and report are warranted to estimate less than one percent of the CO₂e emissions from petroleum refining sector. This is well within the range of calculation error given the calculation methodologies. BP proposes that the required reporting of wastewater treatment emissions be entirely removed from petroleum refining and petrochemical production subsections. Also in the same Technical Document for Petroleum Refineries, on page 18 there is a graph showing the breakdown of greenhouse gases. N₂O and CH₄ together account for less than 1% (on a CO₂e basis) of an average refinery's emissions. These should also be able to be counted in the de minimis threshold.

Response: Please see Sections II.K and III.Y.3 of the preamble for responses to this comment. In regard to wastewater treatment, EPA is not going final at this time with that source category; please see Section III.II of the preamble and the relevant comment/response document.

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

Commenter Name: See Table 2

Commenter Affiliation:

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

Comment Excerpt Number: 186

Comment: §98.253. Standard conditions are defined in §98.6 as 60 °F and 14.7 psia. However, the molar volume conversion of 849.5 scf/kgmole presented throughout the subsection equates to 68 °F and 14.7 psia. The correct molar volume conversion should be 836.2 scf/kgmole.

Response: We have amended the definition of Standard Conditions. They now are defined in §98.6 to be 68 °F and 14.7 psia.

Commenter Name: Lorraine Krupa Gershman

Commenter Affiliation: American Chemistry Council (ACC)

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

Comment Excerpt Number: 133

Comment: It is unclear what EPA intended to be covered by the provision for process vents not covered in 98.253(a)-(i) such that §98.253(j) is needed. EPA should provide examples of the types of process vents covered by this provision. EPA should clarify this provision applies to process vents released to the atmosphere after controls if they exist, and this provision should include a de minimis reporting level based on carbon content, flow rate, and/or emissions. EPA has already determined the process vents with the majority of the GHG emissions and specified emission methodologies for them in §98.253(a)-(i). Thus, the emissions from these vents are probably insignificant compared to the total GHG emissions from the refinery.

Response: We agree that the scope of sources covered in §98.253(j) is unclear. It was not our intent to require reporting of every process vent or safety device vent in the refinery. We have added a definition of process vent to clarify pressure relief devices are not considered process

vents. Additionally, we added concentration thresholds for selected GHGs (2% for CO₂; 0.5% for CH₄; and 0.01% for N₂O). If the vent gas cannot reasonably be expected to exceed these thresholds, reporting the GHG emissions for these vents is not required.

Commenter Name: Lorraine Krupa Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2008-0508-0423.2
Comment Excerpt Number: 134

Comment: Section 98.253(k) refers to uncontrolled blowdown systems. The proposed definition of blowdown in 98.6 is a 'manual or automatic opening of valves to relieve pressure and or release natural gas from but not limited to process vessels, compressors, storage vessels or pipelines by venting natural gas to the atmosphere or a flare. This practice is often implemented prior to shutdown or maintenance.' EPA should clarify that 98.253(k) does not apply to vents sent to flares since the emissions from flaring are calculated under 98.253(b).

Response: We agree that blowdown systems routed to a flare are "controlled" and therefore not required to report under §98.253(k). We clarified this by adding "Blowdown systems where the uncondensed gas stream is routed to a flare or similar control device is considered to be controlled and is not required to estimate emissions under this paragraph."

Commenter Name: Renae Schmidt
Commenter Affiliation: CITGO Petroleum Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0726.1
Comment Excerpt Number: 20

Comment: CITGO disagrees with the calculation methodology for flares. Requiring special calculations for each SSM event is an unnecessary burden for a relatively small contributor of the overall GHG emissions at a refinery. Flare minimization has been a recent trend due to implementation of other rules and initiatives and will continue to be a smaller and smaller contributor as flare minimization efforts continue. Refiners should be allowed to use a simpler calculation methodology that does not require separate SSM calculations. While CITGO does agree that composition of flare gas can change, the overall contribution due to this change is minimal on an annualized basis. CITGO does agree that flow monitors and heating value monitors should be used if available. However, CITGO believes that engineering based numbers should be applied to the calculations if such monitors are not in place. It should be recognized that flare sampling (grab samples) has significant safety requirements (including fresh air), requires planning, is time consuming, and normally can not be performed during upset conditions for obvious reasons. Again, requiring extensive monitoring and calculation efforts for a relatively small source (generally 1 to 2 % of the total refinery's GHO emissions) is extremely burdensome and adds little value to any GHO control or management program.

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

Commenter Name: Sam Chamberlain
Commenter Affiliation: Murphy Oil Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0625

Comment Excerpt Number: 35

Comment: EPA requires reporting of CO₂, CH₄, and N₂O - Subpart Y, page 16541. EPA proposes a hybrid approach using a default emission factor for normal operations and a specific engineering analysis for high flare volumes during SSM (Startup, Shutdown, Maintenance). For flares fired with refinery fuel gas Murphy has evaluated the EPA options for flow measurement by continuous measurement or by engineering calculation and carbon content by high heating value (HHV) measurement daily or calculation per 98.33 (a) for heat content; equation C-1, page 16631. EPA allows us to apply a factor of 60kg CO₂/MMBTU HHV and/or use equation Y-1 to calculate CO₂ emissions. For SSM and we may use engineering calculation and process knowledge to estimate the carbon content being flared. Murphy supports the EPA options for calculating flare emissions and has evaluated our processes to determine applicability. However, we do not want EPA to usurp the state's authority and programs regarding flare emissions, performance or calculations.

Response: We have added additional options and clarifications for the flare monitoring requirements. We see no disagreement with EPA's approach. We do not expect that the reporting requirements for flares in the final rule will have any impact on the State's authority or programs concerning flares, performance, or calculation requirements. However, we also note that the State's requirements do not usurp the federal requirements of this rule. While we strived to provide practical and flexible reporting requirements for flares, if the State's reporting requirements are different, then the emissions reported to the State for their purposes may differ from those reported for this rule. This rule does not preempt or usurp a state's authority regarding flare emissions.

Commenter Name: See Table 1

Commenter Affiliation:

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

Comment Excerpt Number: 60

Comment: In Section 98.253(c)(2), the catalytic cracking calculation has two calculation choices. The first calculation method references the use of a continuous CO₂ CEMS for the final exhaust stack. The second calculation method states "you must continuously monitor the O₂, CO, and CO₂ concentrations in the exhaust stack from the catalytic cracking regenerator". In this second calculation, what does continuously monitor mean? Can this be a PEMS/parametric equation or does it have to be a CEMS? We request clarification of this requirement.

Response: We clarify in the final rule that, for the purpose of the O₂, CO, and CO₂ monitoring requirement, hourly measurements suffice. A periodic emission monitoring system that monitors at least hourly is allowed.

Commenter Name: See Table 1

Commenter Affiliation:

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

Comment Excerpt Number: 63

Comment: In Section 98.253, a dimensional analysis of Equations Y-4 and Y-5 indicates that these equations are not correct. Using the emission factors in Tables C-1 and C-3 for "EmF1"

and “EmF2” respectively, the units of measure in Equations Y-4 and Y-5 do not yield results in metric tons of CH₄ and N₂O. [Refer to table in Section IX, page 51, of data submittal for equation provided by commenter.]

Response: Thank you for noting this error. We have corrected the equation in the final rule.

Commenter Name: Gregory A. Wilkins

Commenter Affiliation: Marathon Oil Corporation

Document Control Number: EPA-HQ-OAR-2008-0508-0712.1

Comment Excerpt Number: 71

Comment: Although EPA states that a site specific carbon content factor may be developed, no details are provided on the requirements for development. Marathon interprets that the factor may be developed based on available data including design information as the procedure for developing the factor is not outlined in the rule. Also Marathon believes that the 0.2 default mole fraction of carbon in the sour gas stream is too high. Marathon continues to support that this is an insignificant source and should be allowed as de minimis according to the comment presented above.

Response: If a facility has routine measurement data, these data must be used. However, Marathon is correct in that the default factor can be estimated through limited measurement data or engineering calculations. We have clarified this paragraph to expressly allow engineering calculations. Please note that the basis of these engineering calculations, if used, must be documented. The default 0.2 mole fraction is consistent with the CARB Mandatory GHG Reporting rule and is technically sound. In regard to a de minimis provision, please see Sections II.K and III.Y.3 of the preamble.

Commenter Name: Gregory A. Wilkins

Commenter Affiliation: Marathon Oil Corporation

Document Control Number: EPA-HQ-OAR-2008-0508-0712.1

Comment Excerpt Number: 72

Comment: If EPA continues to require estimating emissions from SRU's, Marathon requests clarification on the feed streams to the SRU that are subject under this rule. There are two feeds to the Claus unit, amine acid gas and sour water stripper gas. The acid gas may contain some CO₂ however the sour water stripper gas will not. It is assumed that the rule applies only to the amine acid gas and not the sour water stripper gas but the rule is not clear on this. The feed volume to the SRU should be allowed to be corrected to remove the volume of sour water stripper gas if it is included in the total volume.

Response: The sour water stripper gas may not contain CO₂, but it may contain light hydrocarbons. That is why we require a carbon content estimate and not just monitoring of CO₂. It is our intent that the total carbon flow to the SRU be estimated to project the potential CO₂ process-related emissions. Therefore, we are clarifying in this response to comment document that we consider the phrase “sour gas feed to the sulfur recovery plant” to include any sulfur containing gas streams that are sent to the sulfur recovery plant for treatment, including sour water stripper gas. We have also clarified in the rule in the terms for the calculation that the

appropriate volumetric flow for use in the equation is the “Volumetric flow rate of sour gas feed (including sour water stripper gas) to the sulfur recovery plant (scf/year).”

Commenter Name: Gregory A. Wilkins

Commenter Affiliation: Marathon Oil Corporation

Document Control Number: EPA-HQ-OAR-2008-0508-0712.1

Comment Excerpt Number: 73

Comment: The tail gas treating unit recycles about 5% of the amine acid gas back to the SRU. The feed meters include this recycle stream resulting in emissions estimates that would be 5% too high unless entities are allowed to subtract this amount from the flow meters. Marathon proposes that this subtraction be allowed to avoid double counting.

Response: We agree. We have included a paragraph to this section to describe a situation that allows an engineering correction to be made and provides a default 95 percent correction factor.

Commenter Name: Lynn D. Westfall

Commenter Affiliation: Tesoro Corporation

Document Control Number: EPA-HQ-OAR-2008-0508-0669.1

Comment Excerpt Number: 3

Comment: A dimensional analysis of Equations Y-4 and Y-5 shows that these equations are not correct. Using the emission factors in Tables C-1 and C-3 for "EmF1" and "EmF2" respectively, the units of measure in Equations Y-4 and Y-5 do not yield results in metric tons of CH₄ and N₂O. As an example, here is the dimensional analysis for Equation Y-4: CH₄ (tonne/yr) = CO₂ tonne/yr*((kgCO₂/mmBTU)/(kg CH₄/mmBTU)) Canceling the mmBTU divisors yields: CH₄ (tonne/yr) = CO₂ tonne/yr*(kg CO₂)/(kg CH₄) The same result applies to Equation Y-5. Based on this analysis, it appears that: 1. To yield the proper pollutants in the numerator and denominator the correct equations should be: Y-4: CH₄ = CO₂ * EmF2/EmF, Y-5: N₂O = CO₂ * EmF2/ErinFi 2. Additionally, the units of measure for the emission factors in Tables C-1 and C-3 should be in tonne/yr rather than kg/yr. Based on this, we question whether the numerical values listed for these emission factors in Tables C-1 and C-3 are correct since the units of measure are not consistent with the equations used in Subpart Y.

Response: We have corrected these equations in the final rule. Further, kg/mmbtu cancels out in the ratio, therefore, the remaining units are in metric tons (i.e., tonnes) per year. It is not necessary nor is it appropriate to provide emission factors in units of metric tons per year.

Commenter Name: See Table 2

Commenter Affiliation:

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

Comment Excerpt Number: 185

Comment: [Page 16683]Sec. 98.253 Calculating GHG emissions. Flares operate over a very wide range of flows and measurement devices are often calibrated to be more accurate at the high or low end of the expected flow depending on the perceived need to be more accurate for routine flaring or upset flaring. When operated outside this range the reporter should attempt to

use engineering methods to determine a more reliable estimate. API offers the following revised language for this section's paragraph (b) at this time. (b) For flares, calculate GHG emissions according to the requirements in paragraphs (b)(1) and (2) of this section for combustion systems fired with refinery fuel gas. (1) Calculate the CO₂ emissions according to the applicable requirements in paragraphs (b)(1)(i) through (iii) of this section. (i) Flow measurement. If you have a continuous flow monitor on the flare, you must use the measured flow rates when the monitor is operational and within the calibrated range of the measurement device to calculate the flare gas flow. If you do not have a continuous flow monitor on the flare or for the periods when the flow was outside its calibrated range, you must use engineering calculations, company records, or similar estimates of volumetric flare gas flow. (ii) Carbon content. If you have a continuous higher heating value monitor or carbon content monitor on the flare or if you monitor these parameters at least daily, you must use the measured heat value or carbon content value in calculating the CO₂ emissions from the flare. If you monitor carbon content, calculate the CO₂ emissions from the flare using the applicable equation in Sec. 98.33(a). If you monitor heat content, calculate the CO₂ emissions from the flare using the applicable equation in Sec. 98.33(a) and the default emission factor of 60 kilograms CO₂/MMBtu on a higher heating value basis. If you measure the density or specific gravity of the flare, you must use a correlation of the density or specific gravity to the carbon content of the gas to determine the emissions factor.

Response: We generally agree with these comments. We have allowed engineering calculations for flare flow when the flow is outside the calibrated range of the flow meter. We have also amended the flare equation to be more consistent with similar types of calculations performed in subpart C (stationary combustion sources), and have provided some clarification and guidance on how to use the equations if mass flow measurements are made to address when and how to adjust the flare gas flow rate based on the average molecular weight (i.e., to address the specific gravity correction comment).

Commenter Name: See Table 2

Commenter Affiliation:

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

Comment Excerpt Number: 204

Comment: §98.253(l). The equipment-based emission factors in Eq. Y-14 (e.g. 0.4 metric tons CH₄/yratmospheric crude oil distillation columns) should be defined in the variable definitions.

Response: As noted, these are equipment-based emission factors expressed in metric tons of CH₄ per year per unit. These values were derived based on correlations and assumptions and are generalized. We see no need to define each separate number used in the equation. The equation is easily understood and applied based on the information provided.

Commenter Name: See Table 2

Commenter Affiliation:

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

Comment Excerpt Number: 187

Comment: §98.253(b)(ii, iii). The headings for sections §98.253(b)(ii, iii) do not clearly match the purpose of the section, leaving the regulations for refinery flare CO₂ emission estimation confusing. The regulations/section headings should be clarified.

Response: We agree and have attempted to clarify these headers.

Commenter Name: See Table 2

Commenter Affiliation:

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

Comment Excerpt Number: 189

Comment: §98.253(b). The CO₂ emission calculations for refinery flares do not take combustion efficiency into account. However, both the definition of flare combustion efficiency (p 16621) and the flare equation in Subpart W (p 16677) provide a 98% flare efficiency for steam or air aspirated flares.

Response: We have revised the equations for flares based on 98 percent combustion efficiency.

Commenter Name: See Table 2

Commenter Affiliation:

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

Comment Excerpt Number: 190

Comment: §98.253(b). Brackets should be added to Eq. Y-1 to indicate the proper use of the summation. In addition, the use of the variable “N” or “n” should be consistent. (In the variable definition, the letter is lower-case.)

Response: We have added brackets for the summation. The subscript “N” in “Flare_{Norm}” is used to indicate “normal” flare flow and distinguish it from SSM flare flow (Flare_{SSM}). The variable “n” is the number of SSM exceeding the reporting threshold for special calculations. These two are intentionally different and we used “p” as the index for the summation calculation so that these subscripts would be distinctly different from the subscripts to distinguish normal and SSM flare flows. We have revised our nomenclature slightly to use “Flare_{Norm}” for the “normal” flare flow, to help clarify that this input is independent of “n”.

Commenter Name: See Table 2

Commenter Affiliation:

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

Comment Excerpt Number: 191

Comment: §98.253(c). Brackets should be added to Eq. Y-2 to indicate the proper use of the summation.

Response: We have added brackets for the summation.

Commenter Name: See Table 2

Commenter Affiliation:

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

Comment Excerpt Number: 192

Comment: 98.253(c), (e) and (g): Regarding the estimation of CH₄ and N₂O from the following processes: catalytic cracking, catalyst reforming, and coke calcining - the “coke” used in the rule for this determination is petroleum coke, a product. However, the processes applying this conversion are catalyst coke. The emission factors are not appropriate for catalyst coke. An assumption of 0 emissions is as accurate as applying the proposed methodologies.

Response: The commenter provides no data to support their position that there are no CH₄ and N₂O from “catalyst” coke burn-off. The coke deposited on the catalyst particles are petroleum based and are expected to have very similar if not identical properties to “petroleum coke.” In fact the EIA definition of petroleum coke includes both marketable coke and catalyst coke: “Petroleum Coke. A residue high in carbon content and low in hydrogen that is the final product of thermal decomposition in the condensation process in cracking. This product is reported as marketable coke or catalyst coke. The conversion is 5 barrels (of 42 U.S. gallons each) per short ton. Coke from petroleum has a heating value of 6.024 million Btu per barrel.” The primary distinction therefore between “petroleum” or “marketable” coke is that the catalyst coke cannot be recovered as a product. The combustion conditions in these units typically have limited oxygen, which would likely increase the emissions of CH₄ and N₂O compared to traditional combustion of petroleum coke in a boiler or furnace. We disagree with the commenter and express our desire to obtain actual data on which to base our policy decisions rather than to simply assume no emissions.

Commenter Name: See Table 2

Commenter Affiliation:

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

Comment Excerpt Number: 193

Comment: §98.253(c). As currently defined, the variables EmF1 and EmF2 are being misapplied in Eqs. Y-4 and Y-5. Either the terms should be flipped in the equations or the variable definitions should be switched. As currently presented, CO₂ emissions are being multiplied by a CO₂ emission factor then divided by a CH₄ (or N₂O) emission factor. Also, thought should be given as to whether the two equations should use the same variables (EmF1/EmF2) in two different equations; to avoid confusion they should perhaps be differentiated.

Response: We agree and have revised the equations. We have also denoted the N₂O emission factor to be EmF₃ to avoid confusion caused in the proposed nomenclature.

Commenter Name: See Table 2

Commenter Affiliation:

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

Comment Excerpt Number: 194

Comment: §98.253(e)(2). The catalyst reforming material balance equation (Eq. Y-6) applies a coke burn-off value. This differs from the engineering estimate approaches provided in California’s Mandatory GHG Reporting rule [Citation: §95113(b)(2)] and the API Compendium, which both calculate CO₂ emissions based on the difference between the carbon fraction of the spent catalyst and the carbon fraction of the regenerated catalyst, an equally accurate estimation

method. As noted previously, emission estimates developed under duly enacted state programs should be acceptable and sufficient for meeting reporting obligations.

Response: We were unaware that routine measurements of the carbon fraction on the spent catalyst were made. We anticipated that the variables in the equation provided were more amenable to measurement or estimation, and provided a means to provide a default value when no carbon content data were available. If the carbon fraction of the spent catalyst and the carbon fraction of the regenerated catalyst are measured, this information can be used to calculate the coke burn rate. That is, we do not believe that specifying Equation Y-11 prohibits the use of the carbon fraction measurement approach. In other words, the approach provided in California's Mandatory GHG reporting rule and the API Compendium can be used to calculate the coke burn rate, which is used in Equation Y-11. A facility should use the best data it has available for estimating its coke burn-off from the reforming unit. Because this source is small relative to the catalytic cracking unit coke burn-off emissions, we believe the method we have chosen is suitable. With respect to State-enacted programs, we strived to provide practical and flexible reporting requirements, and we reviewed draft reporting requirements for some states, including California, in attempt to parallel the reporting requirements when possible. However, different State programs may have different requirements. If the State's reporting requirements are different from those provided in the final rule, then the State's requirements do not usurp the federal requirements of this rule. That is, you must report your GHG emissions in compliance with the requirements of this rule, even if you have to use different calculation methods when reporting to the State agency.

Commenter Name: See Table 2

Commenter Affiliation:

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

Comment Excerpt Number: 196

Comment: §98.253(h). Uncontrolled asphalt blowing CH₄ emissions can be calculated using a facility-specific emission factor, as noted in the variable definition for the asphalt blowing emission factor (EFAB) in Eq. Y-10. However, the definition for EFAB when used to calculate controlled CO₂ emissions does not indicate that facility-specific emission factors are allowed. Facility-specific factors should be allowed when estimating both uncontrolled CH₄ and controlled CO₂ emissions from asphalt blowing. In addition, the API Compendium provides a simple emission factor for uncontrolled asphalt blowing from AP-42 (EPA, AP-42, Section 5.1.2.10, 1995). The AP-42 emission factor for asphalt blowing is assumed to be on an air-free basis (AP-42 does not specify this, but notes the factor represents "emissions"). A gas composition is needed to estimate the CH₄ emissions when using the simple emission factor approach.

Response: We reviewed the API Compendium and AP-42 again. We note that the AP-42 emission factor appears to be in mass of THC per kg of asphalt blown. Using the composition data presented in the API Compendium, it appears that only the hydrocarbon content of the gas should be evaluated in assessing the fraction of the THC that is methane. Nevertheless, the emission factor derived by API is higher than we had originally proposed. As we have limited data on which to base the proposed emission factor, we have revised our default CH₄ emission factor for asphalt blowing. A description of how the default factor was derived has been added to the docket. The default factor provided uses the AP-42 emission factor and an assumed methane composition. If the emissions from the asphalt blowing are measured, facilities are

encouraged to use the measured CH₄ emissions rate using the process vent method. If a single test is performed, a site-specific emission factor for the asphalt blowing operations may be used.

Commenter Name: See Table 2

Commenter Affiliation:

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

Comment Excerpt Number: 197

Comment: §98.253(h). For asphalt blowing, EPA assumes that only CH₄ is converted to CO₂. This ignores other carbon compounds (C₂+). The API Compendium cites a study where other carbon compounds are shown to be present in concentrations similar to CH₄, on an air-free basis. The CH₄ factor for asphalt blowing is the same as is used in EPA's Inventory of Greenhouse Gas Emissions and Sinks, which is based on 1% CH₄. This value is not consistent with the study cited in the API Compendium, which suggest a CH₄ concentration of 13%, on an air free basis.

Response: We reviewed the available information and we agree with the commenter. Consequently, we have revised our default CH₄ emission factor for asphalt blowing to be equivalent to that presented in the API Compendium.

Commenter Name: See Table 2

Commenter Affiliation:

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

Comment Excerpt Number: 198

Comment: §98.253(i). Reporters with delayed coking units are required to calculate CH₄ emissions from the depressurization of the coking unit vessel to the atmosphere using the methods from process vents not specifically referenced and to calculate CH₄ emissions from the subsequent opening of the vessel for coke cutting operations. Methane emissions from the depressuring of coking unit vessels and during coke cutting are small and should be considered as de minimis. Coking unit vessels are typically depressured and steamed, initially to the main fractionator ("little steam"), and then at higher rates through a quench column into a closed blowdown system ("big steam). Methane contained in the wet gas depressured from the coking vessel will end up in the coker gas plant during the "little steam" and in the overhead of the blowdown system settler during the "big steam". The uncondensed gases off the blowdown settling drum are routed to an offgas vapor recovery system or a fuel gas system. (see Figure 2 in the following citation: www.conocophillips.com/NR/rdonlyres/0470A627-E691-49AF-BBF6-F83AD3F44F9A/0/05PTQCokingArticle.pdf) Therefore, any CH₄ present in the coke drum will ultimately end up in a fuel system. The methodologies proposed in the rule to account for CH₄ emissions from coke drum depressuring and coke drilling operations appear to not account for this practice. The coke drum is then usually water quenched and drained, and only then opened to the atmosphere. Considering this typical practice of preparing a coke drum for cutting, Eq. Y-11, proposed for calculating CH₄ emissions from the coke cutting operation seems to have many sources of error which will significantly overestimate the quantity of CH₄ during cutting. Eq. Y-11 is based upon the empty volume of the coke drum. In fact the drum is not empty when it is opened for cutting, but rather is 85-90% loaded with coke. Therefore, the volume term (H*?D²/4) should be multiplied by the in-drum porosity of the coke, ?. The Petroleum Refinery TSD indicates that coke is "quite porous". While there is not an abundance of data on this term, the maximum porosity for coke is generally considered to be 0.20 or less, which API would

argue falls short of quite porous. However, Eq. Y-11 should also adjust for the ratio of the absolute pressure of the coke drum when it is opened (usually 2-10 psig) to the atmosphere $[(P_{\text{depressure}} + P_{\text{atm}}) / P_{\text{atm}}]$. Given a typical degassing pressure of 5 psig and the above referenced maximum porosity of 0.20, the addition of these terms reduces the expected CH_4 to the atmosphere during coke cutting by approximately a factor of 0.27 from what is proposed in the rule. However, the largest error comes from the default CH_4 concentration assumed, (0.03 kgmole CH_4 /kg-mole of gas). Given that the coke drum has already been steamed to the blowdown system for 1-1.5 hours, it seems unreasonable to use a default CH_4 concentration of 0.03 mole percent, which was estimated as 10% of the concentration of CH_4 in coker dry gas. Given the steaming that has taken place, API believes the default value is off by at least an order of magnitude. If all of these corrections are incorporated, the true value is lower than what is predicted by Eq. Y-11 by a factor of 0.03. API thinks these data support the assessment that this operation is indeed de minimum with regard to emissions of CH_4 and other greenhouse gases from coking vessel unit depressuring and coke cutting operations.

Response: We have edited the delayed coking equation to include the pressure correction $[(\text{Coking Vessel Pressure} + \text{Atmospheric Pressure}) / \text{Atmospheric Pressure}]$ and the void fraction terms. The pressure correction term was not included in the original equation because the depressurization vent was required to be monitored, and the vessel was assumed to be at atmospheric pressure when it was opened. However, with the inclusion of this pressure term, this equation can now be used to include both the vent and cutting operations. The commenter did not provide any data to support the porosity value of 0.2. Descriptions of coke produced in delayed coking units are often referred to as sponge coke due to visible macro porous structure. These descriptions are not commensurate with a porosity of 0.2. Additionally, data from source test indicate that a significant fraction of the drum is completely void of coke so that the top portion of the coke drum (coke outage) would have a porosity of 1. We evaluated data on the dimensions of the coke drums, the coke outage, and the mass of coke produced as reported in four source tests of delayed coking units as cited in the Technical Support Document. While we did have difficulty finding particle density data for “green” petroleum coke, particle densities of between 1.4 and 2 g/cm³ were reported. Using these particle densities, the mass of coke produced, and the filled volume of the coke drum, coke bed densities of 0.2 to 0.6 were calculated. Accounting for the coke outage, the void fraction of the drum ranged from 0.54 to 0.72. We selected 0.6 as a central tendency value for the data and have provided a default porosity of 0.6 in the final rule. With respect to the default methane composition, we had measured data for four delayed coking units. While there was significant variability in the methane concentration, the default value is reasonable based on the data we have available. The commenter provided no data to support their position that this value is off by an order of magnitude. The commenter’s argument - “given the steaming that has taken place” - is not compelling, especially in light of the commenter’s suggestion that the coke bed porosity is 0.2. We do recognize that the proposed value was based on typical dry basis concentration and a low-end moisture content. We re-analyzed the data from the delayed coking unit source tests, and rather than using the dry concentrations and assuming a moisture content, we evaluated the reported wet concentrations. We found that the wet basis methane concentration were very consistent, with 3 of the 4 source tests yielding average methane concentrations within 10 percent of 0.01 mole fraction (on a wet basis). Based on this refined analysis, it does appear that the proposed 0.03 mole fraction default is too high. Consequently, we revised the default value for the methane concentration in the final rule to be 0.01 mole fraction and we clarified that this concentration is on a wet basis.

Commenter Name: See Table 2

Commenter Affiliation:

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

Comment Excerpt Number: 200

Comment: §98.253(j). In Eq. Y-12, the use of the variable “N” or “n” should be consistent. (In the variable definition, the letter is upper-case.)

Response: We amended the equation to use a “p” rather than an “n” to indicate the index number of the summation, and we added the definition of “p” to the variable list.

Commenter Name: See Table 2

Commenter Affiliation:

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

Comment Excerpt Number: 201

Comment: §98.253(k). EPA’s intention for sources covered by the provision for uncontrolled blowdown systems is unclear. The definition in §98.6 says ‘blowdown’ means “manual or automatic opening of valves to relieve pressure and or release natural gas from but not limited to process vessels, compressors, storage vessels or pipelines by venting natural gas to the atmosphere or a flare. This practice is often implemented prior to shutdown or maintenance.” EPA should clarify that §98.253(k) does not apply to vents sent to flares since the emissions from flaring are calculated under §98.253(b). For a 500,000 barrel of crude per year refinery (upper bounds for crude throughput), the CH₄ emissions calculated by equation Y-8 is 1.3 metric tons per year. According to the Table Y-2 on page 16540 of the preamble, 99.3% of the U.S. refineries have direct GHG emissions that exceed 10,000 metric tons CO_{2e} per year. Thus, the emissions from uncontrolled blowdown systems from a large refinery are conservatively less than 0.013% of the refinery’s total direct GHG emissions. Even if the intermediate products received from off-site are assumed to be equal to the crude rate, which is an over estimate, the blowdown emissions become 2.6 metric tons per year or 0.026% of the refinery’s total GHG emissions. This level of reporting is not consistent with EPA’s stated intended purpose of the rule which is to support analysis of future policy decisions (pg 16468).

Response: Please see Sections II.K and III.Y.3 of the preamble as well as EPA-HQ-OAR-2008-0508-0631.1, Excerpt 30 and EPA-HQ-OAR-2008-0508-0423.2, Excerpt 134.

Commenter Name: Karen St. John

Commenter Affiliation: BP America Inc. (BP)

Document Control Number: EPA-HQ-OAR-2008-0508-0631.1

Comment Excerpt Number: 100

Comment: Within Subpart Y, Section 98.253(m) references EPA TANKS Model version 4.09D as an appropriate tool to estimate methane emissions from storage tanks. BP requests that TANKS ESP also be referenced in Section 98.253(m). TANKS ESP is a proprietary product based on the same AP-42 storage tank emission calculation equations as EPA TANKS version 4.09D. TANKS ESP is based in Microsoft Excel and can easily be incorporated into facility data management systems and EPA TANKS 4.09D can not. TANKS ESP has also corrected errors in EPA TANKS and has enhanced capabilities. TANKS ESP is also an accepted calculation tool by

a number of state regulatory agencies At the very least, EPA should modify the language of Section 98.253(m) and allow reporter the option of using EPA TANKS version 4.09D, or calculate tank emissions using the appropriate AP-42 calculation methods and tools that utilize those calculation methods.

Response: We amended this language to refer to AP-42 Section 7.1 to allow use of the TANKS model as well as other models based on the AP-42 correlation equations. We could not obtain a copy of TANKS ESP, so we could not evaluate it specifically. However, if this software package implements the equations in AP-42 Section 7.1, then it could be used to estimate methane emissions from storage tanks for the purposes of this final rule.

6. MONITORING AND QA/QC REQUIREMENTS

Commenter Name: See Table 2

Commenter Affiliation:

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

Comment Excerpt Number: 207

Comment: [Page 16688]Sec. 98.254 Monitoring and QA/QC requirements. For Subpart Y Sec. 98.254, API offers the following revised text at this time. (a) All fuel flow meters, gas composition monitors, and heating value monitors that are used to provide data for the GHG emissions calculations shall be calibrated or verified following good industry practice, using a suitable method published by a consensus standards organization (e.g., ASTM, ASME, API, AGA, etc.). Alternatively, calibration or verification procedures specified by the device manufacturer or developed by the facility may be used. Fuel flow meters, gas composition monitors, and heating value monitors shall be recalibrated or re-verified either annually or at the minimum frequency consistent with good industry practice. (b) The owner or operator shall document the procedures used to ensure the accuracy of the estimates of fuel usage, gas composition, and heating value including but not limited to calibration of weighing equipment, fuel flow meters, and other measurement devices. If the calibration or verification frequency is other than annual, the owner or operator will document the basis for the selection of the interval. The estimated accuracy of measurements made with these devices shall also be recorded, and the technical basis for these estimates shall be provided. (c) All CO₂ CEMS and flow rate monitors used for direct measurement of GHG emissions must comply with the QA procedures in Sec. 98.34(e).

Response: We prefer to specify “suitable” methods in the rule. However, we find that there may be many suitable methods from various consensus standard organizations that we are not readily familiar with. Therefore, while we provide a list of specific standards for various monitoring requirements, we also allow the use of other methods published by consensus standard organizations. If a method is used other than those specified, the reporter must provide the method used as well as a rationale for its use. We disagree with the commenter that the calibration frequency should be established by the reporting facility (e.g., “good industry practice”). Such open requirements would not be acceptable for EPA verification of reported results because they would introduce an unacceptable amount of uncertainty and inconsistency across reporters. We do allow calibration at the frequency specified by the equipment manufacturer.

Commenter Name: See Table 2

Commenter Affiliation:

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

Comment Excerpt Number: 206

Comment: §98.254. Catalytic cracking units calculating emissions using Eq. Y-3 as an alternative to using a CO₂ CEMS are required to monitor %CO, %CO₂, and %O₂. According to 40 CFR §63 Subpart UUU, these continuous parameter monitoring systems must be installed, operated, and maintained each according to the requirements §63.1572(c). However, 40 CFR §63.1572 is not incorporated by reference in §98.254; §98.254 only addresses CO₂ CEMS and flow rate monitors.

Response: We have expanded the discussion of applicable methods in §98.254 and have included references to §63.1572 (of subpart UUU) as appropriate. However, subpart UUU does not specify CO₂ monitoring requirements directly. The CO₂ monitoring requirements for catalytic cracking units are specified more completely in Part 60 in §60.105a(b)(2), which references the QA procedures in Procedure 1, 40 CFR part 60, Appendix F. As the CEMS monitoring requirements in this final rule allow QA procedures used under Part 60, we believe that the final rule requirements appropriately consider and cross-reference Part 63 subpart UUU where appropriate.

Commenter Name: Gregory A. Wilkins

Commenter Affiliation: Marathon Oil Corporation

Document Control Number: EPA-HQ-OAR-2008-0508-0712.1

Comment Excerpt Number: 82

Comment: Marathon interprets that when there is no specific requirement outlined in the rule for metering volume, that engineering estimates of volumes are allowed. An example would be the requirement for the annual volume of asphalt blown in an asphalt blowing operation. It should be allowed that if a metered volume is not available, an engineering estimate of the volume be allowed.

Response: We have clarified that the volume of petroleum process streams, including the quantity of asphalt blown, can be determined using company records (without specifying how these volumes are measured or estimated). The uncertainty in the emission factors used in these equations far exceeds the uncertainty in the volume measurement methods used at refineries (which are generally very low as many of these are purchased volumes or product volumes), so the lack of specificity for these volume measurements does not introduce additional uncertainty in the estimated emissions.

Commenter Name: Gregory A. Wilkins

Commenter Affiliation: Marathon Oil Corporation

Document Control Number: EPA-HQ-OAR-2008-0508-0712.1

Comment Excerpt Number: 70

Comment: Marathon supports not requiring sampling of the SRU acid gas stream because of safety concerns and because the stream is de minimis. Sampling of the acid gas is done rarely because it requires a specialized team to catch and analyze the sample due to safety concerns.

Response: We have finalized options that allow use of limited measurement data (e.g., a single measurement or a series of measurements over a limited number of days) to determine a site-specific carbon content in the sour gas feed.

Commenter Name: Karen St. John

Commenter Affiliation: BP America Inc. (BP)

Document Control Number: EPA-HQ-OAR-2008-0508-0631.1

Comment Excerpt Number: 68

Comment: In addition Section 98.254(a), which addresses calibration requirements for Petroleum Refineries, should be modified to reflect the use and reliance on good manufacturing practices. Suggested language is provided: (a) All fuel flow meters, gas composition monitors, and heating value monitors that are used to provide data for the GHG emissions calculations shall be calibrated or verified following good manufacturing practices, using a suitable method published by a consensus standards organization (e.g., ASTM, ASME, API, AGA, etc.). Alternatively, calibration or verification procedures specified by the device manufacturer or developed by the facility may be used. Fuel flow meters, gas composition monitors, and heating value monitors shall be recalibrated either annually or at the minimum frequency consistent with good manufacturing practices.

Response: Please see response to comment EPA-HQ-OAR-2008-0508-0679.1, Excerpt No. 207 of this document.

Commenter Name: Renae Schmidt

Commenter Affiliation: CITGO Petroleum Corporation

Document Control Number: EPA-HQ-OAR-2008-0508-0726.1

Comment Excerpt Number: 23

Comment: Part 75 requires annual dp cell calibrations for orifice meters. However, it also requires visual inspection of the orifice plate every 3 years. This will be a problem since there are some heaters that can go 8 years between TA Also, flow meter accuracy must be within 2% of the upper range value. 40 CFR 98.7 contains 56 specified test methods; of these, 13 (23%) deal with flow. Comparing the standard test methods for flow meters with the calibration methods specified in 40 CFR 75 App. 3 (§2.I.5.1), 98.7 appears to have a few more flow calibration methods listed. One at 98.7(t)(4) seems particularly relevant: While the method American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 22-Testing Protocol, Section 2-Differential Pressure Flow Measurement Devices, First Edition, August 2005 is not specifically called out in 40 CFR 75, it may be useful for GHG measurement.

Response: We prefer to specify “suitable” methods in the rule. However, we find that there may be many suitable methods from various consensus standard organizations that we are not readily familiar with. Therefore, while we provide a list of specific standards for various monitoring requirements, we also allow the use of other methods published by consensus

standard organizations. This general reference allows the use of the cited API method or other appropriate methods that are published by consensus standard organizations.

Commenter Name: Renae Schmidt
Commenter Affiliation: CITGO Petroleum Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0726.1
Comment Excerpt Number: 22

Comment: CITGO agrees that a reasonable quality control program for fuel gas meters makes sense. However, the requirements stated in this paragraph appear to be inconsistent with the Subpart C QA-QC requirements. Subpart Y should clearly state that monitoring and QA-QC under Subpart C apply to all combustion sources. These requirements are based on the applicable combustion source tier. This tiered approach makes sense and properly applies the appropriate level of controls to amount of contribution by combustion sources. This paragraph should have a qualifying statement at the beginning of the paragraph to reference Subpart C for combustion sources and that any requirement for other refinery sources should follow the requirements of this paragraph. Again, it makes little sense to require extensive quality control for small sources or those sources using "assumed" factors.

Response: EPA agrees with this comment. This was the intent of our language in §98.252(a). However, we also added clarifying language in §98.254(a) to indicate that monitoring and QA/QC requirements in subpart C are to be followed for stationary combustion sources at the refinery.

Commenter Name: Renae Schmidt
Commenter Affiliation: CITGO Petroleum Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0726.1
Comment Excerpt Number: 21

Comment: CITGO believes that most sources are insignificant and should not be included in the GHG reporting for refineries unless these sources are significant contributors (at least 1% of total GHG at a refinery). Currently, the rule does not have a threshold "cutoff" making every process vent susceptible to this reporting rule. Most air compliance rules governing process vents have an established "threshold".

Response: Please see Sections II.K and III.Y.3 of the preamble as well as EPA-HQ-OAR-2008-0508-0423.2, Excerpt No. 133 of this document for responses to this comment.

Commenter Name: Gary F. Lindgren
Commenter Affiliation: Calumet Specialty Products Partner, L.P.
Document Control Number: EPA-HQ-OAR-2008-0508-0626.1
Comment Excerpt Number: 12

Comment: The requirement for daily monitoring of refinery fuel gas is not needed for data quality, is unsafe, and unnecessarily expensive. EPA has significantly underestimated the costs of this requirement.

Response: Please see EPA-HQ-OAR-2008-0508-0603.1, excerpt 11 for the response to this comment.

Commenter Name: Matt Smorch

Commenter Affiliation: Countrymark Cooperative, LLP

Document Control Number: EPA-HQ-OAR-2008-0508-1081.1

Comment Excerpt Number: 11

Comment: QA/QC requirements call for annual calibration and certification of flow meters used to estimate emissions. Countrymark believes that this is an overly cumbersome and expensive requirement as flow meter maintenance is basic in every refinery operation. Many of the flow meters are used for yield and energy calculations and are critical to efficient operation. Refineries should have the flexibility to calculate flow meters based on operating experience instead of arbitrary time limits and procedures.

Response: We have revised the calibration frequency requirements for flow meters in the final rule to be calibrated biennially (every 2 years) or the frequency specified by the manufacturer.

7. PROCEDURES FOR ESTIMATING MISSING DATA

Commenter Name: See Table 2

Commenter Affiliation:

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

Comment Excerpt Number: 208

Comment: Sec. 98.255 Procedures for estimating missing data. A complete record of all measured parameters used in the GHG emissions calculations is required (e.g., concentrations, flow rates, fuel heating values, carbon content values). Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a CEMS malfunctions during unit operation or if a required fuel sample is not taken), a substitute data value for the missing parameter shall be used in the calculations. API comments: API noticed an inconsistency in the missing data requirements between Subparts C and y. There is also an inconsistency within Subpart Y on the missing data procedures to use. Some systems, such as laboratory information systems, used to calculate the reported quantity, store or use the last valid value for calculations until it the value is updated. For reasons of good business controls, it would be better to restrict user intervention to reset input values to a minimum case where the intervention makes a significant difference. This saves effort on making minor edits and improves documentation of the development of the reported values. (a) For each missing value of the heat content, carbon content, or molecular weight of the fuel, the substitute data value shall be the quality-assured value of that parameter immediately preceding the missing data incident. If the quality assured value immediately following the missing data incident is different by more than ten percent of the preceding value, the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident will be used. If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.

Response: We agree that consistency between subpart C and subpart Y is important. In both subparts C and Y, for each missing value of the heat content, carbon content, or molecular weight of the fuel, the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident must be used. Averaging the values before and after a missing data incident only when they differ by greater than 10 percent does not appear to significantly improve the accuracy of the substitute data. We believe that the arithmetic average is a better indicator of the missing data, and it is better to have a consistent method for all missing data rather than having to evaluate and document a 10 percent change in the before and after values. However, for missing concentrations, gas flow rate, and percent moisture, the substitute data values can be the best available estimates of the parameters, based on all available process data.

Commenter Name: Renae Schmidt
Commenter Affiliation: CITGO Petroleum Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0726.1
Comment Excerpt Number: 24

Comment: This paragraph is completely inconsistent with the preamble. EPA clearly stated in the preamble that data substitution for missing data in the Petroleum Refinery source category be the arithmetic average of the parameter immediately preceding and immediately following the missing data. The Part 75 missing data algorithm referenced in this paragraph is extremely burdensome and completely unnecessary for the types of GHG emissions that should be reported by the refineries. CITGO strongly recommends that EPA delete this inconsistent requirement.

Response: We agree and have deleted this reference to Part 75. The missing data requirements for subpart Y have been revised to reflect those in subpart C.

Commenter Name: Gregory A. Wilkins
Commenter Affiliation: Marathon Oil Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0712.1
Comment Excerpt Number: 15

Comment: Marathon requests that EPA maintain consistency for missing data procedures across all subparts (Subpart C and a portion of Subpart Y have different requirements). Additionally, there is inconsistency within Subpart Y on the missing data procedures to use. In Subpart Y, §98.252(a), EPA states that, "For each stationary combustion unit, you must follow the calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements specified in Subpart C of this part." Subpart C allows for best engineering estimates for missing data on flow meters. Then in another section in Subpart Y, §98.255(b), EPA states, "For missing oil and gas flow rates, use the standard missing data procedures in section 2.4.2 of appendix D to part 75 of this chapter." Marathon proposes that consistency throughout the rule should be maintained and that the missing data procedures for flow meters outlined in Subpart C should be used for the specific subparts including Subpart Y.

Response: We agree and have revised the missing data requirements in subpart Y to reflect those in subpart C.

8. DATA REPORTING REQUIREMENTS

Commenter Name: Renae Schmidt

Commenter Affiliation: CITGO Petroleum Corporation

Document Control Number: EPA-HQ-OAR-2008-0508-0726.1

Comment Excerpt Number: 25

Comment: CITGO agrees that a reasonable set of records should be kept to verify or defend reporting GHG emissions. However, reporting nearly all of the records that should be maintained makes little sense and creates a significant reporting burden as well as making the electronic reporting process extremely complex. The reporting requirements in this paragraph are inconsistent with other regulatory programs that rely on reasonable record keeping. The intent of reporting should be to "report the facts" and any "key exceptions". Reporting should never be at a level to support duplication of calculations. Also, excessive reporting can "bog down" any electronic reporting system, insert confusion into the reporting process and create concerns about confidentiality. Instead, EPA should focus on the key records that need to be kept to undertake verification and support any anticipated GHG management program. Additional data can be added I requested if the need should arise, but upfront, excessive reporting should be avoided. The reported information should focus on emissions. The annual emission inventory and TRI reports should be used as general guidance for GHG reporting. Lessons learned from the reporting structures should be applied. Again, focusing on the significant GHG contributors significantly reduces unnecessary reporting and allows better focus (thus quality) on the key GHG contributors.

Response: Detailed reporting is needed to support EPA self-verification. Without the supporting data, EPA cannot verify the calculations. We have reviewed and revised the data reporting elements to ensure all equation inputs are reported so the reported GHG emissions can be calculated. For further response to this comment, please see the response to comment document Volume No.: 13, Subpart A: Content of the Annual Report, the Abbreviated Emission Report, Recordkeeping, and the QAPP.

Commenter Name: D. Lawrence Zink

Commenter Affiliation: Montana Sulphur & Chemical Company Inc. (MSCC)

Document Control Number: EPA-HQ-OAR-2008-0508-0505.1

Comment Excerpt Number: 13

Comment: Our facility is an independently owned and operated sulfur recovery facility, using acid gas raw materials provided by nearby refineries. We also remove the sulfur from sour fuel gas that is provided by the refineries, return fuel gases to the refineries, and conduct other activities. We believe that under the proposed rule we are required to consider and possibly report only GHGs generated on our site from the combustion of fuels in process heaters, incinerators, and boilers – specifically when they are combusting natural gas or low sulfur fuel gas – and not the emissions arising from processing (combusting) acid gas or sour gas, and then only if these select emissions exceed 25,000 metric tons in a given year. We understand that the refineries are tasked with reporting the potential (or actual) emissions from their "sour gas" sent off-site for processing, (whether or not all of that gas is returned to them) and ask confirmation

of that. Who reports the emissions of CO₂e originating in acid gas raw material? Is the material to be double-reported?

Response: We confirm that petroleum refineries are required to estimate and report the CO₂e originating in acid gas raw material. MSCC would not be required to report these emissions, so they will not be double counted. Assuming MSCC contains no other process covered by this rule, MSCC would only be required to report emissions from stationary combustion units, and then only if the stationary combustion source emissions exceed 25,000 metric tons in a given year.

9. COST DATA

Commenter Name: See Table 1

Commenter Affiliation:

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

Comment Excerpt Number: 15

Comment: The costs associated with implementing this inventory program on the petroleum and petrochemical industry have been significantly underestimated. Capital for equipment, development of procedures and programs, data collection infrastructure, and manpower requirements are all significantly greater than that characterized in the proposed rule, preamble, and Regulatory Impact Analysis. By EPA's own estimates, this rule will cost on average \$0.04 per metric ton. Based on the estimated emissions and number of affected facilities (as provided by EPA), this estimate alone amounts to \$54,400 per refinery, over twice the Regulatory Impact Analysis (RIA) estimated impact to the refining industry. Given the size and complexity of refining and petrochemical operations, it is puzzling how EPA can portray the financial impact at less than half the national average. In keeping with Section IV of the rule preamble, Rationale for the General Reporting, Recordkeeping and Verification Requirements That Apply to All Source Categories, paragraph (2), in which EPA requests costs information, we offer the following observations and qualifications of EPA costs estimates to industry, based on our knowledge of operations and experience with other regulatory programs under development, such as those in California. Generally, EPA has estimated the following impact to the refining industry: Refining 1st year costs (industry-wide): \$1.6 million Refining 1st year total annualized costs (industry-wide): \$3.7 million Annualized capital costs per refinery: \$1,200 Annual O&M costs per refinery: \$7,300 Annual labor costs per refinery: \$6,500 Annual electricity use: \$1,700 First Year Impact per Refinery: \$21,000 Annualized Costs per Refinery: \$16,700 The bases for these estimates are documented in the RIA. The underlying assumptions in generating this estimate, and specific errors we have identified, are discussed below. a. Cost Estimate Underlying Assumptions: Generally, EPA's analysis presumes that those sources with CO₂ CEMs already installed will use the existing data. For other combustion sources, pre-existing HHV, carbon content, and flow monitor data can be used. Lacking all of these, EPA provides a series of equations and sampling requirements to determine emissions of CO₂. Ultimately, EPA's approach appears to minimize capital cost expenditures by relying on monitoring equipment already in-service and allowing engineering calculations supplemented with sampling to fulfill the remaining data requirements. Since this proposal does not specifically require the use of CEMs or monitors unless one is present (with the exception of FCC/Cokers), EPA assumed there are few capital costs associated with monitoring. Per the RIA, annualized capital costs are estimated at \$1200 per facility over the entire industry, which is significantly lower than our

member companies expect. There are errors in EPA's costs resulting from multiple simplifications and oversights with this approach. These errors lead to underestimates in the cost to comply: CO₂ has not historically been a regulated pollutant. Consequently, existing facility CEMs/monitors are not necessarily for "regulatory" purposes and thus may not meet the accuracy requirements of the rule. In many instances, meeting the more stringent requirements of a regulatory action that must be certified/verified will require monitor replacement. This is also true for HHV, carbon content, and flow meters that are used for internal requirements and not "regulatory" purposes. Higher Tier sources will require upgrades in order to meet the prescribed data collection requirements. Many of these sources are on fixed unit outage schedules that extend 4 or 5 years. The rule should allow for a phase-in approach to avoid additional burdens to affected sources that include excess emissions from early shutdowns, lost production opportunities, potential safety risks from compressed hazard reviews required under PSM, and potentially dangerous hot-tap work to add nozzles on fuel and flue lines while in service and prior to a scheduled outage.

1. The EPA analysis incorrectly assumed the lifespan of this equipment is 15 years in determining annualized costs. Refineries are a demanding environment, with many of these monitors in corrosive/extreme service. Industry experience suggests 10 years is a realistic life span for this equipment. This will change the Capital Recovery Factor from 0.1098 to 0.1424 and increase the estimated annualized costs by a corresponding 33%.
2. Refineries have many small, discrete gas streams that are not routed through the main fuel gas headers and subsequently not captured by a central fuel gas analysis/monitoring system. These streams may be routed directly into a fuel gas combustion device. Under this rule, these sources of fuel must be accounted for either through direct monitoring or sampling programs, again at considerable costs. This will affect EPA's presumption in the RIA of only two "fuel gas systems" per refinery.
3. Refineries may have more than two "fuel gas systems," especially complex refineries, with H₂ or flexicokers providing supplemental fuel gas.
4. Monitors would need to be installed and operational by January 1, 2010. This is an extremely aggressive schedule which would require facilities to order equipment on an expedited basis, increasing the costs of monitors by 20%. Furthermore, it is extremely likely that this schedule will not be met if hundreds of monitors are suddenly required.
5. Cost for the certification and testing of each existing and new CEM will be much greater than the costs premised in the RIA. With regard to the specific assumptions used in the "model emission source", as documented in the RIA Appendix, the following factual errors are noted:
 1. CO₂ CEMs costs are at least twice as high as EPA used in the analysis. The EPA estimate is \$9,408, while a literature review indicate that 2009 costs range upward to more than \$25,000 for some instruments, and increase dramatically if further instrumentation infrastructure is necessary, such as instrument shelters (in excess of \$100,000).
 2. The RIA does not account for the costs of purchasing and installing new data acquisition and data management systems which will likely be required with the significant increase in CEMs and monitoring systems.
 3. HHV monitors, as noted by SCAQMD Flare rule analysis, run approximately \$75,000 each. While they are not specifically required by this rule either for fuel gas for flare monitoring, this must be compared against manpower costs of daily sampling, as noted below.
 4. EPA assumed that 50% of sources perform "more detailed estimation methods" (e.g., Method 21) for equipment leaks. While this assumption may be correct, it does not take into account the required P&ID review and cross reference with speciation data, expansion of the monitoring program, and the data management system added/adjusted for the difference in monitoring obligations (methane is not a VOC, and thus tracking its concentration for compliance purposes has been unnecessary). This initial LDAR revision work is estimated at \$50,000 to \$100,000, depending on the size of the facility. All refiners will need to undertake this action. The methane fugitive obligations will expand all refiners' LDAR programs and annual costs by an estimated 20%.
 5. No discussion is provided on the costs associated with developing and maintaining the GHG inventory "infrastructure". Given

EPA's push in recent years for electronic reporting, it is envisioned that EPA will require reporting of GHG information electronically. Consequently, each refinery must expend the technical resources to develop, or at a minimum modify, the software/hardware configuration to account for new substances, new sources of data, etc. GHG inventory software could increase costs beyond \$50,000 for a site-wide license. 6. The flare discussion does not include costs associated with flowmeter installation and lost-opportunity costs due to unit down time. Flare flowmeters should not be installed with the flare in operation. As a safety device, a flare cannot be shut down without the process unit(s) it serves also being shutdown. Due to the strict timeline for implementation in this proposal, facilities cannot wait until the next refinery turn-around cycle for the necessary process units to be removed from service in order to install equipment on the flare. Consequently, operating units must be shutdown out-of cycle. The lost opportunity associated with this varies by unit type and size, but for FCC units, can be in excess of \$1 million daily. b. RIA Analysis In the RIA Analysis, EPA provides a breakdown of the average labor, capital, and O&M costs associated with implementing this proposal. In light of the errors highlighted above, the following are noted: 1. EPA assumes the initial labor/engineering manpower needed for planning, QA/QC, recordkeeping, reporting, sampling and analysis at 173 hours (21.6 working days – approximately 1 month). It is not possible to execute this rule in what EPA has calculated to be 1 person working for 1 month. Staffing needs are significantly greater initially and involve many disciplines throughout the refinery: Process Engineering, Information Services, Instrumentation, Maintenance, Purchasing, Management, etc. The California Air Resources Board surveyed the refining industry and found that staffing needs for initial compliance with their GHG inventory rule amounted to \$500,000 to \$700,000 per facility. Using EPA's labor costs, this amounts to over 7,830 combined man-hours to execute a GHG inventory regulation. This is significantly greater than EPA's estimated initial labor costs of \$12,292. 2. Subsequently, the projected ongoing labor costs by EPA are also significantly underestimated. For instance, it is unrealistic to assume that 4 hours a year will be spent on QA/QC activities. A more realistic assumption would be to assume a minimum of 4 hours per month per CEM to account for daily, monthly and quarterly QA/QC evaluations. In addition, additional time is required to address CEM operation and calibration failures, as well as periodic preventative maintenance. 3. Existing operations are continually being revised, with new operations added and old ones removed – all of which must be evaluated regularly. The Management of Change program instituted at many refineries consumes hundreds of hours of combined manpower in tracking changes to operations. 4. Further, allotting 23 man hours annually for sampling, analysis and calculations belies the complexity of this undertaking, especially in light of how little capital EPA believes will be spent on any direct monitoring. Taking EPA's assumptions from the RIA appendix of 3 flare systems and 2 fuel gas systems that require daily sampling for HHV or carbon content, each refinery would need 1,825 samples taken annually. This equates to a total time for each sample at 45 seconds, split between the sample collector and lab technician– clearly unrealistic. At a minimum, EPA should allow 1 hour per sample for collection and analysis, or 1,825 hrs/yr. This increases the ongoing labor costs for sampling, analysis, and calculations from \$1,476 to \$116,600 annually, per facility. Even a. this change may not fully account for the labor and material expenses associated with addressing a failure of the CEM and monitoring system. 5. Monitoring equipment capital costs estimates (including equipment selection, purchase, and installation) are estimated by EPA at \$10,962. Given that industry is not aware of a CO₂ CEMs, Fuel HHV monitor, or fuel carbon content monitor that can be specified, purchased, and installed for this sum, we fail to understand how EPA arrived at this average capital expense per facility. As noted above, we believe monitor costs will run more closely to the following: CO₂ CEMs: \$20,000 to \$25,000, plus installation Fuel HHV monitors: \$75,000 plus installation Fuel Carbon Content monitors: \$50,000 - \$80,000 plus installation Instrument shed: \$65,000 to \$100,000 each (Please note that due to anti-trust

concerns, we are unable to provide full information and are therefore providing some examples) For average capital expenses per refinery at approx \$11,000 (EPA estimate in the RIA), this equates to a total capital expense by the industry of \$1,644,000 (in close agreement with estimates elsewhere in this proposal). By comparison, CARB’s rulemaking survey indicated that capital expenses ranged in excess of \$725,000 per facility. Annualizing these costs (based on EPA’s original set of parameters: 15 years/7%), yields approximately \$80,000 per facility, as compared to EPA’s estimate of \$1,200 per facility. 6. Overall, the management and oversight of a compliance-driven inventory program will require the equivalent of an additional headcount at each refinery – approximately \$100,000 + for O&M at each refinery. c. Baseline Reporting Estimates EPA does not have enough information on current internal practices to reach any industry-wide conclusion that supports the supposition that a “baseline” inventory program exists, with costs already incurred such that the differential produced by this rule is less significant. Regulatory actions are mostly not simply “add-on” requirements to existing practices. Realistically, industries must, to a large extent, scrap existing internal programs in favor of new regulatory requirements for a significant number of reasons, including: 1) Data accuracy requirements conflict with those of existing work-practices or monitoring equipment, leading to the development of different programs and replacement of monitoring equipment. 2) GHG data and inventory infrastructure will be different due to a greater focus on insignificant sources. Manpower efforts will increase sharply to include multiple sources with minimal impact on the total inventory. 3) Reporting deadlines are different, leading to periods where GHG reporting will conflict with other significant regulatory deadlines, taxing available manpower and requiring review and reallocation of staffing needs. 4) Managerial certification requirements introduce significant manpower in the review and validation of data that are not required for internal purposes. d. Verification Costs Verification estimates for the refining sector are greater than the \$5,000 documented in the RIA, with literature values ranging from \$7,500 to \$10,000 based on today’s regulatory climate outside of California. In agreement with the CARB study cited in the RIA document, costs for large and complex industrial operations such as refineries are expected to approach \$20,000 due to demand outstripping supply. It is expected that a national rule will drive nationwide impacts commensurate with that seen in California. Finally, EPA’s estimates of the social costs of the this rule are flawed as they are based on the erroneous presumption that compliance costs, as outlined above, are insignificant and thus will not affect prices or quantities in affected markets. EPA states, “Overall national costs of the rule are significant because there are a large number of affected entities, but per entity costs are low. Average cost-to-sales ratios for establishments in affected NAICS codes are uniformly less than 0.8 percent. These low average cost-to-sales ratios indicate that the proposed rule is unlikely to result in significant changes in firms’ production decisions or other behavioral changes, and thus unlikely to result in significant changes in prices or quantities in affected markets”. This assumption, in turn, allowed EPA to use the Guidelines for Preparing Economic Analyses (EPA, 2002, p. 124–125) and use the engineering cost estimates to measure the social cost of the proposed rule, rather than modeling market responses and using the resulting measures of social cost. This conclusion will require revisiting in light of the above cost corrections.

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

Commenter Name: Sam Chamberlain

Commenter Affiliation: Murphy Oil Corporation

Document Control Number: EPA-HQ-OAR-2008-0508-0625

Comment Excerpt Number: 16

Comment: EPA presents its summary cost analysis data in the preamble with further details in the accompanying regulatory impact assessment (RIA) report. Based on these documents EPA expects the cost for this rule (2006\$) to be \$168MM and falling to \$134MM from the second year on, with 95% of the cost to be borne by the affected industry. When attempting to analyze the cost impact on a given industry sector or facility, the numbers are a bit misleading. EPA is presenting cost data for each of the subparts separately but fails to consider the overall burden per facility in view of the fact that most industry facilities are subject to more than one subpart and could be subject to more than the combined compliance burden if additional staff would be required to ensure compliance with the full gamut of provisions. A few examples, from Table VIII-1 of the preamble, can be used for demonstration: a. General Stationary Fuel Combustion accounts for 6% of downstream emissions, but its first year total annualized costs would amount to 17% of the total share. b. Oil and natural gas systems account for 3% downstream emissions but its first year total annualized costs are estimated to be 19% of the total share. c. Petroleum refineries are estimated to account for 5% of the downstream emissions with an estimate that their total annualized cost is 2% of overall costs. This figure does account for the cost of reporting for the stationary combustion units, or for electricity generation from cogeneration systems, which many refineries have installed to increase their energy efficiency and reduce the intensity of GHG emissions. On top of that refineries would also have to bear the cost of reporting under the landfill and wastewater provisions. d. The development and implementation of a Quality Assurance Performance Plan (QAPP) required by this regulation goes far beyond the level of sophisticated quality plans refineries and other operations use today. Additionally, EPA's estimate for the cost per facility is probably low in particular when it comes to addressing fugitive emissions, since the total cost does not reflect data for the cost of inspections and maintenance. Please note: Table VIII exhibits Petroleum Refineries twice, once showing an average cost per facility at \$19K and the second time at \$24K. We have been conducting our own internal GHG inventory worldwide. Our annual average costs equate to about \$250,000 per year. This includes consultant costs (\$150,000) and an estimated one man-year of effort (\$100,000). For our USA facilities, including both upstream and downstream operations, this would equate to about \$187,500 (75% of total costs) per year for conducting the GHG inventory. Based on EPA's unrealistic estimates of cost per facility, Murphy's practical estimates are almost by a factor of three or four higher than the EPA data (the average costs per refinery are about \$62,500 for two refineries in the USA and relatively the same costs for our USA upstream emissions inventory efforts). The EPA should go slowly in its efforts to implement such a complex and costly burden to industry, especially to those who have not conducted such an inventory in the past. These costs do not include the additional costs to comply with the onerous QAPP plan, operations and maintenance, etc.

Response: Please see Section III.Y.3 of the preamble for the response to this comment. Regarding industrial landfills, EPA is not going final with that source category at this time; please see Section III.HH of the preamble and the relevant comment/response document. In regard to wastewater treatment, EPA is not going final with that source category at this time; please see Section III.II of the preamble and the relevant comment/response document.

Commenter Name: Gary F. Lindgren

Commenter Affiliation: Calumet Specialty Products Partner, L.P.

Document Control Number: EPA-HQ-OAR-2008-0508-0626.1

Comment Excerpt Number: 16

Comment: EPA should reassess the assumptions and shortcuts used in its calculation of costs of initial and ongoing compliance with the proposed rule. Very preliminary estimates Calumet's costs show them to be much higher than those identified in the proposed rule. Additional time is necessary to better quantify and better comment on the actual costs of compliance, as well as to propose alternative approaches.

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

Commenter Name: Matt Smorch

Commenter Affiliation: Countrymark Cooperative, LLP

Document Control Number: EPA-HQ-OAR-2008-0508-1081.1

Comment Excerpt Number: 5

Comment: Countrymark feels that the ongoing cost of compliance with the rule will be substantial and it will have to establish an additional position in its compliance department at roughly the cost of \$100,000 including benefits and will also require the use of an independent contractor in excess of \$50,000 per year.

Response: Please see Section III.Y.3 of the preamble for the response to this comment. Further, we note that EPA's cost estimates are provided for an average refinery. Costs for an individual refinery will vary and may be higher than the average for very large facilities or for facilities that have a higher than average number of lines that do not have existing monitors but which require sampling.

Commenter Name: Sally V. Allen

Commenter Affiliation: Gary-Williams Energy Corporation

Document Control Number: EPA-HQ-OAR-2008-0508-0982.1

Comment Excerpt Number: 2

Comment: The cost of compliance for SBRs will be significantly higher than the EPA proposal suggests. We note, for example, that the California Air Resources Board (CARB), on the basis of a refinery survey, has estimated that staffing needs for initial compliance with the state GHG inventory rule will total \$500,000 to \$700,000 per facility. Ongoing labor costs for sampling, analysis and calculations will also be significant. We will have to add at least one full time professional staff at each plant. In addition, most of our small companies do not now have the sophisticated monitoring systems that will be required to comply with this rule. The GARB survey noted above suggested that that the capital costs for selection, purchase and installation of monitoring equipment (such as CO₂ Continuous Emissions Monitors, Fuel HHV monitors, Fuel Carbon Tent Monitors and Instrument sheds) could exceed \$725,000 per facility. Even this total is significantly understated. One small refiner, for example, has received a proposal for the installation of an in-line GC monitor (Gas Chromatograph) costing \$1.735 million. Most SBRs will have to employ consultants and engineers to assist in gathering this data, at a time when numerous companies will be seeking the same expert assistance. If such consulting and engineering firms can be found, the costs will be high. One SBR reports that they have received an initial proposal from a firm for \$26,000 for "a Phase 1 evaluation to make an initial approximation of their baseline". That proposal assumed the company could provide the necessary data inputs of mass and energy balances for all plant units, fuel utilization data,

electrical distribution data, energy consumption data and emissions records – information they do not currently have.

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

Commenter Name: See Table 1

Commenter Affiliation:

Document Control Number: EPA-HQ-OAR-2008-0508-0433.1

Comment Excerpt Number: 10

Comment: The costs associated with implementing this inventory program on the petroleum and petrochemical industry have been underestimated significantly. Capital for equipment, development of procedures and programs, data collection infrastructure, and manpower requirements are all significantly greater than that characterized in the proposed rule, preamble, and Regulatory Impact Analysis.

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

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2008-0508-2167.1

Comment Excerpt Number: 1

Comment: The following summarizes API member company feedback on parameters EPA used to develop the cost implications for Subpart Y. The responses below represent feedback from 7 U.S. refineries, with capacities ranging from 50 to over 300 KBPCD (thousand barrels per calendar day).

Process Heaters and Boilers:

1. EPA assumes that the average refinery has 2 fuel gas systems. API members indicated that the number of fuel gas systems can range from 1 to 7 per refinery.
2. EPA assumes that 12 heaters and/or boilers are serviced by each fuel gas system. API members indicated that EPA's assumption is low and can actually range from 11 to 68 heaters and/or boilers are serviced by each fuel gas system. This supports API's request to not have to report unit level combustion information.
3. EPA assumes 90% of fuel gas systems have equipment to monitor flow rate and heat value content. Feedback from API members varied. A refinery may have flow meters, but heat value content is done by grab sample; a refinery may use a lab GC for fuel gas analysis every day, a refinery may only have heat value content monitors, or a refinery may have flow rate monitors but calculate heating value based on specific gravity.
4. EPA assumes 20% of individual process heaters and boilers have CEMS on the exhaust stack. API members indicated that this could vary from none to 60%.

Flares:

1. EPA assumes 3 flares per refinery. API members indicated that this could range from 0 to 7.
2. EPA assumes 20% of flares have monitors for flow rate and heating value content. Feedback from API members varied. A refinery may have flow monitors and molecular weight monitors on all flares; another may determine HHV and TOC by GC in a sampler only during a flaring event; while another may use panametric flow meters.

FCCUs/FCUs:

API member feedback on the number of FCCUs/FCUs with equipment to monitor coke-burn rate or CEMS that monitor final stack CO₂ were consistent with EPA's assumptions.

Sulfur Recovery Plants:

1. EPA assumes 10% of sulfur recovery plants have CEMS to monitor inlet sour gas flow and composition. Feedback from API members varied. A refinery may have a monitor to measure flow of H₂S, SO₂ and O₂; another may have flow monitors, but the only composition data is sulfides and ammonia from lab samples.
2. EPA assumes 5% of sulfur recovery plants have CEMS that monitor final stack CO₂. None of the refineries represented by the survey responses have CEMS.

Other Fugitive Sources (equipment leaks, storage vessels):

1. EPA treats fugitive sources as one general source per refinery. Costs developed based on 150 petroleum refineries. API members indicated that the number of fugitive components associated with stream containing CH₄ or CO₂ could vary from 1,000 to 125,000 per refinery. Some refineries have not yet determined this count since these emission sources are not included in current LDAR programs.
2. API members indicated that the data required to run TANKS may not be currently collected for some refineries.

Costs:

1. EPA assumed the following cost elements:
Labor Costs - \$12,300 for 1st year, \$6,500 for subsequent years;
Capital Costs - \$1,200 per year;
Equipment O&M - \$7,300 per year;
Electricity Use, Recordkeeping and Reporting Costs: \$1,700 per entity.
2. API members indicated that the annual costs associated with the additional O&M, reporting, monitoring, and QA/QC from the MRR could range from \$100,000 to 600,000 per refinery.
3. API members also indicated that the annual costs associated with constructing the GHG inventory to comply with the rule could range from \$20,000 to \$1,250,000 per refinery.

Response: We thank you for the information provided by the commenter. In general, it appears that many of the assumptions made at proposal regarding the various sources were reasonable. We note that, although the commenter provided information for a wide range of refineries, a 50,000 bbl/cd refinery is representative of the 33rd percentile refinery in the database and a 300,000 bbl/cd refinery is representative of the 93rd percentile refinery. Therefore, the responses are likely to be skewed high and not represent the smaller one-third of refineries. We also considered this information in light of the final rule requirements. We then re-assessed our costs based on the comments received. For additional details regarding our revised cost analysis, please see our response in Section III.Y.3 of the preamble.

Table 1

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 2

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