

ACC Recommendations for the EPA GHG Reporting Rule

- As required by other GHG registries and EPA programs, GHG emissions should be reported on a facility basis, and not by individual units. Facilities should only be required to submit the final GHG emissions, and maintain the supporting data for transmittal to EPA upon request. Submitting volumes of supporting data is not necessary, and much of it will be CBI.
- Facilities will not be able to comply with a requirement to install new instrumentation to record and report emissions in 2010. For at least 2010, facilities must be allowed to utilize existing instrumentation, engineering practices, process knowledge, estimates and judgment in reporting emissions.
- Facilities should have until July 1 of each year to report annual GHG emissions. This deadline aligns with other facility reporting requirements, such as TRI, as well as other existing GHG reporting regimes. A March 31 deadline does not provide facilities with sufficient time to complete the calculations, especially considering that many utilities do not provide final annual fuel usage data until mid- to late February.
- EPA should allow a facility to estimate emissions using simplified calculation methodologies from sources that collectively comprise up to 5% of a site's total emissions. This *de minimis* provision would enable facilities to avoid capital investment (e.g. new flow meters) and unit shutdowns just to capture additional emission data for minor sources or, in some cases, avoid detailed calculations for small point sources, while still ensuring facilities report total GHG emissions. Both the California mandatory reporting rule and the Climate Registry include *de minimis* provisions.
- There is no reason a facility should have to continue reporting GHG emissions if its emissions drop below the required reporting threshold. Requiring the continued reporting of emissions is a disincentive for facilities to take steps voluntarily to reduce GHG emissions. EPA should adopt California's position, and allow facilities to stop reporting once emissions drop below the mandated threshold for three years.
- Ethylene production facilities should be removed from the Petrochemical Production (Subpart X) source category. Emissions associated with these facilities are essentially all combustion related and would be covered under Subpart C of the proposed rule.
- EPA should revise both the PFC definition and HFC definition to reflect the definitions recognized by the scientific community and lists developed by IPCC. Furthermore, EPA should exempt from reporting any fluorinated compounds that are not placed into subsequent emissive uses, as was done in the ozone-depleting substance program.
- EPA should clarify that the hydrogen production subpart is only applicable to commercial hydrogen production facilities, and not those units that incidentally produce hydrogen or hydrogen-containing byproduct gases that are typically combusted.
- It is crucial that EPA recognize that the installation of CEMS and flow monitors poses a financial burden to many facilities without much added benefit; thus EPA should limit the required use of this equipment.

Comments on
EPA's Proposed Rule for Mandatory Reporting
of Greenhouse Gases

74 Federal Register 16448, April 10, 2009
Docket EPA-HQ-OAR-2008-0508

Submitted by
The American Chemistry Council
June 9, 2009

Executive Summary

The Environmental Protection Agency (EPA) presented a comprehensive and detailed proposal for the mandatory reporting of greenhouse gas (GHG) emissions. The American Chemistry Council (ACC) supports EPA's development of a GHG inventory in order to gain a better understanding of the GHG emitted by sources within the U.S. We recognize that this is a challenging undertaking, one that impacts a large portion of the economy. We appreciate EPA's acknowledgement of the magnitude of this rulemaking.

ACC strongly believes that the reporting of GHG emissions should be made on an annual basis. We do urge EPA to push back the reporting submittal deadline from March 31 to July 1 as this will allow facilities time to gather and carefully review emissions data prior to submittal. We also strongly support EPA's proposal of not requiring third-party verification of emissions data. If EPA finalizes 2010 as the first reporting year, it will be necessary for sites to use existing instrumentation and engineering estimates to provide emissions data because there will not be time for all facilities to procure and install the necessary monitoring equipment between the time the rule is finalized and January 1, 2010.

Overall, ACC believes that EPA has made this proposal unnecessarily complex and broad, and targeted fairly small facilities. A reporting threshold of 25,000 MT CO₂e is too low, and a threshold of 100,000 MT CO₂e would greatly reduce the number of affected small facilities while still capturing a great majority of industrial GHG emissions. Furthermore, requiring facilities to continue reporting GHG emissions even after they have lowered emissions to below the threshold provides a disincentive for facilities to reduce emissions.

The prescribed level of detail in the individual source category calculations goes far beyond other regulatory requirements currently imposed on facilities. Requiring weekly and even daily monitoring for flows that vary little will impose great costs for little gains in reporting accuracy. Annual calibration of instruments should not be required where less frequent calibration is specified by equipment manufacturers or authorized by federal, state or local authorities. Furthermore, EPA is requiring the submittal of large quantities of supporting data, much of which is considered Confidential Business Information (CBI), rather than allowing facilities to maintain such records and make them available to EPA upon request as has been the Agency's practice.

In order to reduce some of the burden on facilities, ACC recommends that EPA allow for the estimation of emissions from small point sources. Additionally, EPA should provide a *de minimis* exemption, permitting facilities to estimate emissions using simplified calculations from sources that collectively comprise less than 5% of a site's total emissions.

We believe EPA can make the rule more flexible, thereby reducing the burden on facilities, without compromising the quality and accuracy of the GHG emissions data that will be gathered and submitted under this rule.

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I. Introduction

The American Chemistry Council (ACC)¹ appreciates the opportunity to comment on the Environmental Protection Agency's (EPA) Proposed Rule for mandatory reporting of greenhouse gases (GHG) emissions (74 FR 16448, April 10, 2009). ACC member facilities largely represent NAICS code 325, and thus will be required to report under this rulemaking.

ACC supports EPA's development of a GHG inventory in order to gain a better understanding of the GHG emitted by sources within the U.S. We recognize that this is a challenging undertaking, one that impacts a large portion of the economy. We appreciate EPA's acknowledgement of the magnitude of this rulemaking.

When Congress directed EPA to develop such a rule, Congress gave EPA broad discretion in how to establish the GHG reporting rule. EPA has used this discretion in identifying applicable and proposing source categories and establishing reporting thresholds. For the reasons stated below, we believe that EPA should also use that discretion to ensure that only the largest emitters are targeted for this rulemaking at this time, and provide flexibility for those facilities that are required to report emissions. Permitting simplified calculations where appropriate would result in accurate emissions reporting without the added resources required by the proposal.

ACC members are committed to providing quality data, and are well-versed in the reporting requirements for similar federal reporting programs such as the Toxics Release Inventory (TRI). Our comments were developed to allow the Agency to reach the high level of accuracy it desires while at the same time significantly reducing the cost to and impact on the U.S. economy. We look forward to working with EPA on this rulemaking and any other Agency initiatives relating to the reporting of GHG emissions.

II. Overall comments

This section of our comments highlights the issues of greatest importance to ACC member companies. Many of these issues will also be addressed in Section III of our comments, which focus on the individual source categories.

¹ The American Chemistry Council (ACC) represents the leading companies engaged in the business of chemistry. ACC members apply the science of chemistry to make innovative products and services that make people's lives better, healthier and safer. ACC is committed to improved environmental, health and safety performance through Responsible Care[®], common sense advocacy designed to address major public policy issues, and health and environmental research and product testing. The business of chemistry is a \$664 billion enterprise and a key element of the nation's economy. It is one of the nation's largest exporters, accounting for ten cents out of every dollar in U.S. exports. Chemistry companies are among the largest investors in research and development. Safety and security have always been primary concerns of ACC members, and they have intensified their efforts, working closely with government agencies to improve security and to defend against any threat to the nation's critical infrastructure.

A. Reporting Threshold

We appreciate EPA's acknowledgement of the burden that will be imposed by this rule on reporting facilities in order to provide the Agency with accurate and comprehensive accounting of GHG emissions data in the U.S. To that end, we continue to believe that 100,000 metric tons CO₂e is a more appropriate threshold for reporting than is the proposed 25,000 metric tons.

We believe it is critical that EPA balance the need for GHG data with minimizing the burden on smaller facilities, and a threshold of 100,000 metric tons achieves that balance. However, at a minimum, EPA should review and analyze at least one additional threshold level between 25,000 and 100,000 metric tons.

The FY 2008 Consolidate Appropriations Act simply required EPA to "...develop and publish a draft rule...to require mandatory reporting of greenhouse gas emissions above appropriate thresholds in all sectors of the economy of the United States," and was silent on any reporting thresholds. We have reviewed the information contained in the preamble, and noted the following from page 16467 of the proposal:

"Furthermore, many industry stakeholders that EPA met with expressed support for a 25,000 metric ton of CO₂e threshold because it sufficiently captures the majority of GHG emissions in the U.S., while excluding smaller facilities and sources."

On the contrary, our member facilities reviewed their GHG emissions data, and concluded that the proposed reporting threshold would not exclude a number of smaller facilities and sources. In fact, at a threshold of 25,000 MT CO₂e, many small sources would be obligated to report. While we cannot speak to the meetings or outreach activities EPA held with other stakeholders on reporting thresholds, ACC met with and provided information to EPA several times in the past to discuss reporting thresholds. Specifically, in a letter to EPA dated June 20, 2008, ACC stated the following:

"Any mandatory reporting requirements should require reporting actual or estimated emissions of all six categories of GHGs (CO₂, CH₄, N₂O, SF₆, PFCs, and HFCs) in units of CO₂-e. The rule should require reporting from facilities emitting 100,000 metric tons or more of CO₂-e per year of direct emissions, with no reporting requirements for facilities with less than 100,000 metric tons of CO₂-e per year."

Setting the threshold at 100,000 MT per year of CO₂ e would gather greater than 90 percent of the emissions data from the chemical industry sector, and would exclude small facilities from the need to report and maintain information. Reporting at the 100,000 MT CO₂e annual threshold would also be consistent with the requirements of the European Union Emissions Trading Scheme for general industrial sources, and Canada's mandatory reporting rules. EPA should also be aware that the 25,000 MT per year CO₂e threshold will not only require reporting by a number of small industrial sites, but will also require reporting by commercial entities, universities and other small emitters, and their emissions will only represent a small fraction of U.S. emissions, arguably not worth the burden that will be imposed on them. Thus we recommend that a reporting threshold of 100,000 MT per year of CO₂e emissions be

incorporated into the final reporting rule and that the language at §98.2 (and other pertinent sections) be modified accordingly.

As an alternative, EPA could finalize a rule that phases in reporting thresholds. For example, EPA could require the initial reporting of emissions from facilities that emit greater than 100,000 MT per year of CO₂e, and phase in greater than 50,000 MT CO₂e and 25,000 MT CO₂e per year thresholds at later dates. Doing so would result in the initial reporting of nearly all of the emissions from the chemical industry, allow EPA the opportunity to review this vast data set and then make subsequent determinations on lower reporting thresholds at later dates. Note that this practice is not without precedent. The final Toxic Chemical Release Reporting rules ("Toxic Release Inventory or TRI") set forth three tiers and time periods for reporting. Specifically, the final rules stated the following at 40 CFR 372.25:

"The threshold amounts for purposes of reporting under §372.30 for toxic chemicals are as follows:

(a) *With respect to a toxic chemical manufactured (included imported) or processed at a facility during the following calendar years:*

1987 – 75,000 pounds of the chemical manufactured or processed for the year.

1988 - 50,000 pounds of the chemical manufactured or processed for the year.

1989 – 25,000 pounds of the chemical manufactured or processed for the year."

In the preamble to the final TRI reporting rule (53 FR 4508, February 16, 1988), EPA stated the following:

"EPA agrees with comments to the effect that the first few years' data should be evaluated to determine whether modifications of the threshold would meet the statutory test of obtaining reporting on a substantial majority of the releases (i.e., pounds released per year) of each chemical from subject facilities."

A phased approach with regard to GHG reporting would also enable EPA to obtain a substantial amount of data while satisfying the Congressional requirement to obtain information from all sectors of the economy. If acceptable to EPA, we recommend that as an alternative to the 100,000 metric ton reporting threshold, the proposed language at §98.2 (and other pertinent sections) be modified to accommodate a phased schedule for reporting.

B. Annual reporting

We agree with EPA that GHG emissions data should be reported on an annual basis. However, the proposed rule requires that GHG emissions for a reporting year be submitted by March 31 of the following year. We recommend that this due date be moved to later in the year to better coincide with other reporting requirements. Many States and local regulatory agencies require submittal of a significant number of reports between March and July of each year, which require the dedication of facility resources. In addition, final fuel usage data for the previous year is often not available until late February. This data is a key component in calculating GHG emissions, and would leave companies with only a month to calculate emissions before the March 31 deadline.

We note that the Climate Registry requires data be submitted by June 30, EPA's Climate Leaders has a June 30 deadline, and California's Mandatory GHG emissions reporting program has a June 1 deadline for some source categories. Many companies already have reporting systems set up to meet these existing timelines and this earlier reporting timeframe would require additional reporting resources in order to complete the calculation and reports.

ACC strongly recommends that EPA finalize a reporting deadline of July 1, which is consistent with other GHG reporting programs and coincides with the deadline for data submittal to TRI.

C. Once in, always in

EPA has proposed a "once in, always in" requirement for the GHG reporting rule. This means that once a facility is subject to reporting under 40 CFR Part 98, the facility would always be required to report even if its emissions drop below the reporting threshold. We believe, as EPA has rightly concluded,² that this policy is a huge disincentive for facilities to reduce their GHG emissions. As EPA has continuously stressed with the Toxic Release Inventory (TRI) program under 40 CFR §372, reporting is a significant incentive for facilities to voluntarily reduce their emissions. In addition, while we believe that the costs are underestimated, EPA has calculated the compliance costs for this rule to be \$168 million in the first year,³ which is a huge expense to continue to impose on facilities year after year, and particularly on those that are able to reduce their GHG emissions.

ACC believes that the burdens that will be imposed by this reporting rule will far exceed those of any other reporting rule, including TRI. If a facility is able to reduce their GHG emissions to reduce the economic impact, it should be strongly encouraged to do so. As discussed in more detail in the Section IV of the proposed rule, we support the adoption of the California reporting

² FR, Section IV, p. 16470.

³ FR, Section VIII. A., Table VIII-1, p. 16597

rule provision that would exclude a facility from reporting when the emissions over a 3-year period drop below the thresholds in §98.2(a)(1) or (2).

D. Required data

EPA discusses how detailed data, above and beyond emissions, will have to be submitted to the Agency under Part 98. This represents a significant departure from other EPA programs. As is the norm in such programs as TRI under 40 CFR 372 or the air emission inventory under 40 CFR 51, Subpart A, EPA and the states require only that the final data be submitted and certified. Furthermore, affected facilities are required to maintain all supporting documentation and to make it available to EPA or a state agency upon request. EPA has given no rationale as to why it seeks to abandon this approach and require that all supporting data be submitted so that EPA can perform "quality assurance reviews."

One of our major concerns is the protection of sensitive business information. Some of the supporting data submitted by companies will be Confidential Business Information (CBI) pursuant to 40 CFR Part 2, Subpart B. Because only emission data is required to be made public information, facilities are entitled to CBI protection, when claimed, for the supporting data. EPA acknowledges that the concern about CBI has been raised by stakeholders.⁴ However, the Agency does not discuss these concerns nor explain how they will be addressed, if at all. As stated in the preamble, when facilities make CBI claims under Part 98, EPA will address the issue pursuant to 40 CFR Part 2, Subpart B. Proper treatment of CBI information will increase the burden on the party asserting the claim and on EPA to receive, handle, and store the CBI. This will increase unnecessarily the overall costs of this rule.

We strongly recommend that EPA follow its existing practice in other rules and require only that the GHG emission data be submitted. EPA should require that the supporting data be maintained by the facility and made available to the Agency upon request.

EPA should allow facilities more time to respond for data requests. Requiring a response to a written request within seven days is an impossible deadline. A person might be on vacation, and might not even see the request in that time period. While the records likely will be readily available, it will take a bit of time to compile them and send them. Further, the timing to produce the records may be in conflict with other legally required reporting obligations and result in missing the deadline. EPA should allow a minimum of 30 days to fulfill a data submission request, with an option for an extension if the facility requests it and explains why an extension is needed.

We are concerned about EPA's proposal to request data through an electronic mailing to the facility. We believe it is important for EPA to request any data through a hard copy mailing, with an additional electronic request if desired. Our concern is that facility personnel and email

⁴ FR, Section I, p. 16457

addresses change over time, and it is very likely that a response sent only by email would not be received in a timely manner. Further, with the proliferation of SPAM and unwanted email, it is important that a facility be able to determine when it is in receipt of a legitimate data request.

E. *De minimis* emissions

EPA's proposal does not allow for the designation of emissions as *de minimis* and instead expects each facility to calculate emissions from each affected source, regardless of level of emissions or size. However, other existing greenhouse gas registries allow for the designation of *de minimis* emissions, which typically amount to no more than 5% of a facility's total emissions. We strongly urge EPA to consider adopting such a *de minimis* threshold, which would acknowledge the difficulty in quantifying emissions from small units while still holding facilities to accurate emissions reporting.

California's Mandatory Reporting Rule defines *de minimis* as follows:

"De minimis" means those emissions reported for a source or sources that are calculated using alternative methods selected by the operator, subject to the limits specified in section 95103(a)(6).

California's Section 95103(a)(6) reads as follows:

Emissions Calculation and Reporting Procedures for De Minimis Sources. 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, not to exceed 20,000 metric tonnes 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. The operator shall separately identify and include in the emissions data report the emissions from designated *de minimis* sources. The operator shall determine CO₂ equivalence according to the 100-year global warming potentials provided in Appendix A.

The Climate Registry also recognizes *de minimis* emissions in chapter 11 of its General Reporting Protocol:

"Therefore, in order to reduce the reporting burden while retaining the requirement for complete emission reporting, you are allowed to use alternative, simplified estimation methods for any combination of individual emission sources (e.g., individual electricity generators, vehicles, furnaces, etc.) and/or gases, provided that the emissions from these sources and/or gases are less than or equal to 5 percent of your entity's total emissions."

Note that both of these programs still require the calculation of emissions from all sources, but also recognize the difficulty in determining exact emissions from every point source at a facility. In fact, EPA's supporting memorandum titled "Reporting Methods for Small Emission Points (De Minimis Reporting)" also recognized this problem. The TSD stated that:

"... some facilities that exceed the reporting threshold could have some small sources of certain GHG species. The existing GHG reporting programs provide simplified emissions estimation methods for these small sources, but still require that emissions for all sources have to be reported. This appears to be a practical and feasible approach for the Federal mandatory rule as well."

We strongly urge EPA to adopt a *de minimis* policy that is consistent throughout the reporting rule source categories, and allow for up to 5% of a site's total emissions to be calculated using simplified emissions estimation methods. As the proposal is written, simplified calculations are not allowed at all for many source categories.

F. Research and Development Exemption

A general exemption from the requirements of the reporting rule is requested for research and development (R&D) activities. Emissions from R&D operations are *de minimis*. Without an exemption, however, they would be subject to significant reporting requirements with only small gains in terms of emission coverage.

The rationale for an R&D exemption is clear. The goal of R&D is to be innovative, to try new and different technologies and processes, perform experiments and invent new products along with the methods to make those products. The procedure of trying something new and failing is an integral and accepted part of R&D. In the R&D environment, we routinely deal with small batches, hand mixing and addition of experimental materials. Burdensome reporting requirements add a further, and unnecessary, hurdle to innovation and experimentation.

There is precedence for including an R&D exemption in EPA rules. In Section 112(c)(7) of the Clean Air Act amendments of 1990, which sets the framework for national emission standards for hazardous air pollutants (NESHAPs), Congress recognized the uniqueness of R&D facilities and directed EPA to establish a separate source category for research and laboratory facilities. EPA acknowledged that such a separate category was necessary "to assure equitable treatment of such facilities." (57 FR 31576, July 16, 1992.) EPA has included the R&D exemption in many final NESHAPs, including the petroleum refinery industry NESHAP, the phosphate fertilizer production plant NESHAP, the printing and publishing industry NESHAP, the wood furniture and woodworking NESHAP, the NESHAP covering organic hazardous pollutants from equipment leaks, the magnetic tape manufacturing NESHAP and the hazardous waste combustor NESHAP.

Additionally, in 40 CFR 2.301, a provision dealing with the treatment of confidential information, an exemption is provided for R&D information. The exception for R&D again

recognizes that it is critically important for companies to maintain confidential protection of R&D information.

An exemption for R&D is consistent with the goals of the proposed GHG reporting rule. The preamble to the proposed rule states that the goals include, among others: 1) balancing rule coverage while excluding small entities; and 2) reducing the reporting burden where feasible. (74 FR 16456.)

The intent of the proposed GHG reporting rule appears to focus on large-scale industrial plant operations. Facilities considered to be “covered entities” include such broad manufacturing categories as aluminum production, ammonia manufacturing, cement production, and certain sources that emit or produce more than 25,000 tons of carbon dioxide equivalents. Additionally, the proposed rule speaks in terms of emissions associated with “any stationary source that **produces**, or any entity that **imports, for sale in interstate commerce.**” (Emphasis added.) EPA recognizes “the potential burden of reporting emissions for smaller sources,” (74 FR16473), and describes the proposed rule as affecting “only larger facilities, would require reporting of significant emission points only, and would contain simplified reporting where practicable.” (74 FR 16474.)

The evaluations underlying the requirements of the reporting rule appear not to have considered the costs and technical feasibility of applying the same reporting requirements to certain R&D operations, which are by nature much smaller in scale and operate in an intermittent manner and/or on a “batch” scale. The proposed reporting rule does not contain a general R&D exemption. It only contains an R&D exemption for two of the covered categories, Subpart F – Aluminum Production (which exempts “experimental cells” as well as R&D process units) and Subpart N – Glass Production. Neither the preamble language nor Subparts F and N does not discuss the criteria used to exempt these R&D sources, nor do the technical support documents for these two categories. It is unclear why R&D exemptions are provided for these two categories but not for all categories listed in the rule.

ACC requests that EPA exempt all R&D activities from the reporting rule. The proposed reporting rule defines “research and development process unit” as: “a process unit whose purpose is to conduct research and development for new processes and products and is not engaged in the manufacture of products for commercial sale, except in a *de minimis* manner.” (74 FR 16626.) This definition focuses on the “process unit” and would appear to cover process units which are dedicated solely to R&D and to units which are used for R&D with only a *de minimis* amount of production for sale. However, it does not appear to exempt process units which are used for R&D with greater than a *de minimis* amount of production. ACC requests that all R&D emissions and R&D production (gases produced to be used for further R&D) be exempt from the reporting rule to encourage innovation and experimentation without the burdens of significant reporting obligations.

ACC requests that language specifically be added to the final reporting rule that reads:

“The requirements of this rule do not include research and development activities. Research and development activities are those activities conducted in process units or at laboratory bench-scale settings whose purpose is to conduct research and development

for new processes and products and not for the manufacture of products for commercial sale, except in a *de minimis* manner.”

G. Verification

We strongly support EPA’s proposed approach of requiring self-certification of GHG emissions. At this time, this proposed rule is creating an inventory of GHG emissions, and is not being used for regulatory enforcement. As such, it is unnecessary to impose costly third-party verification on facilities. (Initial cost estimates for facilities requiring third-party verification under California’s rule range from \$5,000/audit for a simple facility to upwards of \$40,000/audit for a complex facility such as a refinery.)

H. 2010 Reporting date

We are concerned that compliance with this complex rulemaking will be required immediately so that 2010 GHG emissions can be gathered and reported. For sources that must comply with the rule, systems and mechanisms to gather data must be put in place, emissions estimates must be compiled, and reporting systems must be established before the end of 2009. Furthermore, reporting entities do not know how such reports are to be made to the EPA, other than the reports will be submitted electronically.

If, for example, EPA developed a final rule by the end of August 2009, it would then need to be reviewed by the Office of Management and Budget (OMB). This review could take 60 to 90 days. If completed within 60 days, and presuming that OMB did not have objection to its issuance, it would be October 2009 before the rule would be ready for publication in the Federal Register. Thus, under the best of circumstances, it is unlikely that a final rule would be published until mid-late October 2009. If EPA chose to require reporting for CY 2010, entities would only have 30 to 45 days to develop and implement data gathering and management systems.

We would like to call attention to EPA’s rulemaking activities associated with another data gathering activity – the TRI reporting rules. On June 4, 1987, EPA published a draft of TRI reporting rules. It was not until February 16, 1988 – eight months later - that EPA published the final TRI reporting rules. The proposed rule contained the TRI reporting form and interpretive requirements for reporting, thus affording the regulated community the opportunity to review and prepare for specific reporting obligations. No such information is contained in the proposed GHG rulemaking. Note also that the TRI reporting rules did not require the use of specific calculation methodologies, but rather allowed a regulated entity to rely on existing engineering practices, estimates and judgment. Specifically, the TRI rules stated the following:

“In order to provide the information required under this section, the owner or operator of a facility may use readily available data (including monitoring data) collected pursuant to other provisions of law, or, where such data are not readily available, reasonable estimates of the amounts involved. Nothing in this section requires the monitoring or

measurement of the quantities, concentration, or frequency of any toxic chemical released into the environment beyond that monitoring and measurement required under other provisions of law or regulation. In order to assure consistency, the Administrator shall require that data be expressed in common units.”

Conversely, the proposed GHG reporting rules have set forth specific and comprehensive data gathering and management requirements, including in some instances, the installation of continuous emission monitors (CEMS), calibration of existing CEMS, etc. Given the complexity of this rule, we recommend that entities be required to submit detailed reports no earlier than 2012 for calendar year 2011 emissions. Any reporting required for 2010 emissions should rely solely on the use of existing engineering practices, estimates and judgment.

I. Title V Implications

EPA should clarify the relationship of the GHG reporting rule and Title V operating permit requirements. We strongly encourage EPA to include language in the final rule that clearly excludes the GHG reporting rule as a Title V applicable requirement.

The Title V operating permit program requires facilities that exceed the Title V operating permit threshold (e.g. 100 tons of VOC for a listed source category; 10 tons of an individual hazardous air pollutant, etc.) to include all federally applicable air requirements in a site permit. The Title V operating program is comprehensive, and includes updating permits for new regulations, reporting of deviations versus permit terms, and submission of compliance certifications by a Responsible Official on a periodic basis. The GHG Reporting Rule is silent on the obligations of a Title V operating permit holders with regards to inclusion of the GHG reporting rule elements.

ACC believes that the GHG Reporting Rule is not an applicable requirement for purposes of the Title V operating permit program. 40 CFR 70.2 defines “applicable requirement” and none of those listed requirements apply to this rulemaking, which EPA stated is being proposed under section 114(a)(1) of the Clean Air Act. (74 FR 16454.) If EPA views that it is an applicable requirement, then it is recommended that EPA clarify that the rule can be included in a permit with a permit term that just notes that a source, if it is determined that the GHG reporting rule is applicable, must comply with the terms and conditions of Part 98, as appropriate. And for Title V operating permit holders, EPA should note that signature by a Title V responsible official eliminates the need for a designated representative and all the regulatory language related to this position in the reporting rule.

J. Applicability

Throughout the rule, there is conflicting information about which activities at a facility are subject to what source category requirements. It is critical that EPA properly and clearly specify applicability to avoid confusion and unintended misreporting by facilities. Some detailed examples are below.

- The applicability description that is contained in Subpart II §98.350(a) describes the source category as follow: “This source category applies to on-site wastewater treatment systems at pulp and paper mills, food processing plants, ethanol production plants, petrochemical facilities, and petroleum refining facilities.” While not stated specifically, this would appear to reference other specific subcategories in the proposed rule, i.e. Subparts AA, M, J, Y, and X. These specific subparts should be referenced in §98.350(a) in order to eliminate any confusion over the affected industries.
- Section 98.270(a) states that the Pulp and Paper Mill source category includes “Chemical recovery combustion units at stand-alone semichemical facilities” and “coating and laminating processes.” The definition of “chemical recovery combustion units” is not specified and there are many facilities that operate coating and laminating processes and more specifically coating and laminating processes that utilize paper substrates. Section 98.270(b) specifically lists those operations where reporting is required. Item (5) includes, “Systems for adding makeup chemicals (CaCO₃, Na₂CO₃).” Based on a literal interpretation of this rule, any facility that operates coating and laminating processes would be required to report emissions for any system that was used for added makeup chemicals, presumably those limited to CaCO₃ and Na₂CO₃. Rule applicability is further complicated by language contained in §98.272 which further describes those processes that must report emissions. Language should be added which clearly limits the scope of the subcategory and excludes those facilities which were not intended to be contained within and have not traditionally been ascribed as being part of the Pulp and Paper Mill source category.
- 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.
- In §98.240, the Petrochemical Product (Subpart X) applies to facilities that produce “acrylonitrile, carbon black, ethylene, ethylene dichloride, ethylene oxide, or methanol as an intended product.” Certain manufacturing operations will produce methanol as a process by-product. For instance, certain polyester manufacturing operations will produce by-product methanol during the manufacture of polyester resin. Applicability language in many other environmental regulations have addressed this type of issue as a part of “primary product” determinations. The applicability language should clearly state that Subpart X source category only includes those facilities (or processes) that produce these materials as primary products.

III. Comments specific to individual source categories/subparts

A. General Provisions – Subpart A

Many of our concerns with reporting thresholds and exemptions have been covered in our Section II comments. Our more detailed concerns within the General Provisions subpart are discussed below.

Reporting Applicability - §98.2

In §§98.2(a)(1) and (a)(2), EPA specifies that reports must cover “all sources...for which calculation methodologies are provided in subparts B through JJ.” This procedure does not take into account very small sources that would require time and effort for an insignificant quantity of emissions. EPA should include wording in this paragraph to address *de minimis* sources. Very small individual sources at a covered facility could conceivably require as much effort as large sources, and yet the emissions from those sources would be insignificant relative to total site emissions. EPA indicates in the preamble that for small stationary combustion units, no fuel measurements would be required. However, that is only applicable to the high heat value (HHV) and CO₂ emission rate factors; fuel use would still need to be metered for very small sources, which is a significant cost and burden. For example, the rule language would require monitoring and reporting of each domestic hot water heater, gas-fired space heater, and gas-fired stove. EPA should allow small individual sources totaling no more than 5% of total site emissions to utilize simplified calculations to estimate emissions.

Section 98.2(a)(1)(i) expands on the definition of electric generating units⁵ under the Acid Rain program by including sources “... that contain electric generating units that collectively emit 25,000 Tc or more per year.” This definition inappropriately groups industrial generation units with electric utility generation facilities. These industrial emissions would be captured in the proposal anyway by sources emitting >25MTe/yr, so it is unnecessary for EPA to include them within the electric generation subset. ACC recommends that EPA delete the portion of the statement “or that contain electric generating units that collectively emit 25,000 metric tons CO₂e or more per year” in the final rule.

Section 98.2(a)(3) covers facilities not specifically listed in §98.2(a)(1) or (2) but whose CO₂e emissions from stationary combustion are >25MTe/yr and aggregate heat input is >30MMBtu/hr. Those facilities only report stationary source emissions. The provision to report only stationary source emissions should be universal to all reporting entities.

Section 98.2(b)(4) provides equation A-1, which specifies that the CO₂e emissions are calculated by multiplying the mass emission of a GHG by the global warming potential of that GHG as found on Table A-1. However, Table A-1 only lists 70 compounds and the vast majority of these are refrigerants and blowing agents. The proposed regulation does not address how to calculate the CO₂e emissions for fluorinated compounds NOT on Table A-1. Does this imply that Table

A-1 is the complete listing of fluorinated GHG compounds subject to the Part 98 regulation? Each compound on the list should be accompanied by a global warming potential (GWP).

Sections 98.2(f) and 98.3(b)(3) specify that a facility or supplier not meeting the threshold must reevaluate applicability whenever there is any change to the facility or supplier that could cause the facility or supplier to meet the applicability requirements, including but not limited to process modifications, increases in operation hours, increases in production, changes in fuel or raw material use, addition of equipment, and facility expansion. Section 98.3(b)(3) requires reporting starting with the first month of the change. This reevaluation apparently does not exempt *de minimis* changes, thus setting up facilities and suppliers with an ever-continuing reevaluation process. The start of reporting presumes every change will trigger reporting when data might not even be available to indicate exceedances until after the fact. This reevaluation requirement should be qualified to be triggered by significant changes relative to prior emission rates or relative to the prior emissions level vs. threshold to minimize efforts. This could alternatively be reevaluated on a periodic frequency rather than not providing any time frame for the reevaluations. These changes are required in order to reduce the burden on both reporters and regulatory authorities.

Monitoring, Reporting, Recordkeeping and Verification Requirements- §98.3

The last sentence of §98.3(d)(4) contains references to equations C-2a and C-9. However, equation C-9 uses the default HHV, not a determined HHV. The correct reference appears to be equation C-10a.

Section 98.3(g)(7) requires reporters to retain a record of the names and documentation of key facility personnel involved in calculating and reporting the GHG emissions. This requirement is excessive given the requirement for reporters to certify each report and inconsistent with the existing Clean Air Programs that require reports to be certified but do not require reporters to retain documentation of personnel involved in gathering emissions data and preparing reports.

Under §98.3(g)(9), reporters are required to maintain a log book documenting procedural changes to the GHG emissions accounting methods and changes to the instrumentation critical to GHG emissions calculations. Documenting the information in a log book is redundant. Under §§98.3(g)(2), (3), (4) and (6), the reporter is required to document the results of all quality assurance tests for continuous monitoring systems and flow meters, the process used to collect the necessary data for the GHG emissions calculations, the GHG emissions calculations, the methods used, and the operating data and process data used for the GHG emissions calculations. The documentation under §§98.3(g)(2), (3), (4) and (6) will show if there was a change to the emissions accounting methods and the instrumentation used to calculate emissions. Finally, the concept of a "log book" is antiquated and not representative of the variety of current day adequate record retention methods. If EPA does not delete §98.3(g)(9), it should be changed. The words "A log book," should be deleted and replaced with "Records."

Section 98.3(g)(11) requires reporters to maintain a written quality assurance performance plan (QAPP) and information collected under the QAPP. At a minimum, this QAPP must include (or refer to separate documents that contain) a detailed description of the procedures that are used

for the maintenance, repair, and calibrations and other quality assurance tests performed on the continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHG emissions report. This requirement is duplicative for CEMS because the rules that trigger their installation already mandate a quality assurance plan. For other continuous monitoring systems, compliance with standard industry practices will assure sufficient maintenance and repair. Also, detailed descriptions of the procedures imply all possible failure modes can be foreseen. This is unrealistic. Sometimes repair procedures are ad hoc because the incident could not be anticipated and the repair is based on trouble shooting results and mechanic knowledge of the equipment. We recommend that EPA recognize and permit the usage of existing QAPPs already in place at facilities.

Designated Representative - §98.4

This section sets forth the requirements for a designated representative (DR), defined as the person who is responsible for certifying and submitting the GHG emissions reports for the owner/operator.

The proposed rule sets an unrealistic expectation for the role of the DR. Section 98.4(e)(1) includes a certification statement containing the following language:

“...I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete...”

This language sets an inappropriate standard for a plant manager with broad responsibilities. A site manager at a complex facility would not have the time to “personally examine” all the documents used to prepare the emissions report in light of his/her many other management responsibilities. A more appropriate standard is the one that is included in the Title V program -- a program that has more substantive requirements that include emission limitations. Under the Title V program, the certification by Responsible Officials is based on “reasonable inquiry” which involves working with and reviewing the facility compliance process and key documents supporting the certification. 40 CFR 71.5(d) requires the certification to state that “...*based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.*”

A second example of a more appropriate standard is in the TRI program, in which the certification statement in 40 CFR 372.85(b)(2) is “*I hereby certify that I have reviewed the attached documents and, to the best of my knowledge and belief, the submitted information is true and complete and that amounts and values in this report are accurate based upon reasonable estimates using data available to the preparer of the report.*”

Furthermore, the provisions for the alternate designated representative set an inappropriate obligation on the original DR. The proposed rule allows for the DR to delegate responsibility to an alternative designate representative. For example, the DR might be on vacation or a medical

leave. However, the rule language in §98.4(f)(1) states that "*...any representation, action, inaction, or submission by the alternate designate representative shall be deemed to be a representation, action, inaction or submission by the designated representative.*" We recommend that 98.4(f)(1) be deleted--- the responsibility should lie with the alternate designate representative.

Finally, the proposed rule requires a certificate of representation which must be revised if the designated representative changes. These provisions are not necessary and just create a paperwork exercise. The Title V operating permit program doesn't require a certification of representation. The responsible individual is the person who signs the certification. Considering the frequency of personnel changes, having facilities send in updated certificates of representation provides no value and creates a paperwork exercise. If this approach is followed by EPA, it should allow for a more generalized certificate of representation, such as "plant manager or his/her delegated representative."

Submitting a Report - §98.5

Under this section, reporters are required to submit reports in a format to be specified by the Administrator. In section III.D (74 FR 16463), EPA states that the "reports would be submitted electronically, in a format to be specified by the Administrator after publication of the final rule. To the extent practicable, [EPA] plan[s] to adapt existing facility reporting program to accept GHG emissions data. [EPA is] developing a new electronic data reporting system for source categories or suppliers for which it is not feasible to use existing reporting mechanisms." EPA further states in section VI.A (74 FR 16593) the "new system would follow Agency standards for design, security, data element and reporting format conformance, and accessibility" and "EPA intends to develop a reporting scheme that minimizes the burden of stakeholders by integrating the new reporting requirements with existing data collection and data management systems, when feasible." EPA acknowledges there are many facets of the reporting scheme, none of which are described in detail in the proposal. Commenters cannot evaluate the reporting scheme without the details and cannot comment on concerns, such as ability to use the electronic system, resources needed to implement the system, and cost associated with the reporting scheme. Thus, we believe that EPA needs to propose the reporting scheme for public comment prior to finalizing it.

Definitions - §98.6

The definition of biomass should be expanded to encompass materials resulting from biofuels production or bio-based materials processing. We recommend that the definition should be revised as follows: "...including products, by-products, residues and waste from agriculture, forestry and related industries, biofuels and bio-based materials industries, as well as the non-fossilized..." This change is to clarify the source of materials for inclusion in biogenic CO₂ emissions.

Compressor fugitive emissions are defined as “natural gas emissions from all components in close physical proximity to compressors where mechanical and thermal cycles may cause elevated emission rates, including but not limited to open-ended blowdown vent stacks, piping and tubing connectors and flanges, pressure relief valves, pneumatic starter open-ended lines, instrument connections, cylinder valve covers, and fuel valves.” We are uncertain as to what is meant by “close physical proximity to compressors where mechanical and thermal cycles may cause elevated emission rates,” and request clarification in the final rule.

Electricity generating unit or EGU definition- “...means any unit that combusts solid, liquid, or gaseous fuel and is physically connected to a generator to produce electricity.” That definition is too inclusive in that it includes all non-utility generating units and associated combustion units. ACC recommends that the definition should be the one used in the Acid Rain Title IV of the Clean Air Act:

ELECTRIC UTILITY STEAM GENERATING UNIT.—The term “electric utility steam generating unit” means any fossil fuel fired combustion unit of more than 25 megawatts that serves a generator that produces electricity for sale. A unit that cogenerates steam and electricity and supplies more than one third of its potential electric output capacity and more than 25 megawatts electrical output to any utility power distribution system for sale shall be considered an electric utility steam generating unit.

The definition of emergency generator states that the hours of operation per calendar year for performance testing shall not exceed 100 hours. The definition in regards to the duration of operation for performance testing should be revised to be consistent with existing Clear Air Act regulations definition for emergency equipment that state testing of units should be minimized, but there is no time limit on the use of emergency equipment in emergency situations and for routine testing and maintenance. See, for example, Stationary Combustion Turbines NESHAP (40 CFR §63.6175) and Stationary Reciprocating Internal Combustion Engines NESHAP (40 CFR §63.6675). Furthermore, the definition of “emergency generator” should be changed to “emergency stationary RICE” to reflect the various types of equipment that can be used by facilities. ACC recommends that EPA utilize the definition in §63.6675:

Emergency stationary RICE means any stationary RICE that operates in an emergency situation. Examples include stationary RICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility is interrupted, or stationary RICE used to pump water in the case of fire or flood, etc. Emergency stationary RICE may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by the manufacturer, the vendor, or the insurance company associated with the engine. Required testing of such units should be minimized, but there is no time limit on the use of emergency stationary RICE in emergency situations and for routine testing and maintenance. Emergency stationary RICE may also operate an additional 50 hours per

year in non-emergency situations.

The definition of “gasification” stipulates that all gasification is limited to conversion of a solid material into a gas. Gasification can also be used to convert liquids into gas, and the definition should be expanded.

There is no definition of “industrial landfill.” However, Subpart HH identifies industrial landfills as sources to be included in the inventory. EPA should add a definition of “industrial landfill” to §98.6.

The definitions of “natural gas,” “natural gas liquids” and “natural gas processing facilities” have an underlying assumption that the primary products of such field operations are natural gas, natural gas liquids and other petroleum based products. We request that these definitions be clarified by including this underlying assumption as part of the language of the definition.

We propose revising the definitions as such, with the proposed new language underlined:

Natural gas means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface of which its constituents include, but are not limited to, methane, heavier hydrocarbons and carbon dioxide.

Natural gas may be field quality (which varies widely) or pipeline quality. For the purposes of this subpart, the definition of natural gas includes similarly constituted fuels such as field production gas, process gas and fuel gas from field operations whose primary intent is to extract hydrocarbons.

EPA should revise the perfluorocarbon (PFC) definition to indicate PFCs are compounds of carbon and fluorine and that all carbon bonds are fully saturated (only single bonds) where IPCC has identified a GWP; and the hydrofluorocarbon (HFC) definition to include only those liquid or gaseous (not including fluoropolymers) compounds containing between one and six hydrogen, fluorine, and carbon compounds identified by IPCC with a GWP.

The definition of “rotameter” appears to exclude the measurement of liquid flow. Thus, for the purposes of Part 98, rotameters that measure liquid flow are not “rotameters”. While §98.6 provides definitions for “meter”, “rotameter” and “turbine meter”, there are numerous other meters mentioned in the proposed rule text that are not defined. Examples include Coriolis meters, orifice meters, ultrasonic flowmeters and vortex flowmeters among other metering devices. ACC suggests that EPA delete the three meter-related definitions in the draft of §98.6 and replace them with a definition of “flowmeter” (a term that appears often, but not exclusively, in the proposed rule) and then use that term consistently throughout Part 98.

The definition of “supplier” appears to exclude the business entities from which most of the emission sources affected by these rules purchase their fossil fuels.

B. Electricity Purchases –Subpart B

ACC believes that EPA should provide facilities with the ability to report purchased electricity and steam on a voluntary basis, in the units it which it was purchased (kWh, steam, etc.) Allowing facilities to report these emissions through EPA's inventory would enable facilities to get a better understanding of the full profile of GHG emissions attributable to themselves. This would also allow for more complete documentation where cogeneration (CHP) facilities are utilized.

C. General Stationary Fuel Combustion Subpart C

Definition of Source Category - §98.30

EPA has not provided a *de minimis* threshold below which the greenhouse gas emissions from a stationary combustion source can be determined using simplified emission estimation techniques. Similar to the discussion above concerning site-wide *de minimis* thresholds, the emissions from the *de minimis* combustion units would still be reported. However, the *de minimis* exemption would avoid the very costly and unnecessary requirement to install flowmeters and perform frequent monitoring on truly insignificant sources such as comfort hot water heaters, gas furnaces for buildings, gas stoves, etc. ACC recommends that EPA add a *de minimis* threshold in §98.31 or §98.32 to allow for the use of simplified emission estimates for emissions from equipment whose emissions fall under the threshold which we recommend to be at least 3 MM Btu/hour.

In §98.30, EPA should also exclude flares, thermal oxidizers, and other air pollution control devices from the definition of stationary combustion sources requiring calculation and reporting of greenhouse gas emissions. These units typically have low emissions, would not have measured flow rates, and do not make a substantial impact on the total greenhouse gas inventory. Any requirement to include these sources would put an unnecessary costly burden on facilities to add flow measurement devices to the feed. For devices such as flares, which may have a widely variable flow rate, there are additional challenges to finding an appropriate flow measurement device capable of covering the range of flows encountered. EPA should clarify that flare emissions should only be included in the calculations of Subpart C of the rule if another subpart of the rule references "flares" or "emission control" equipment as a greenhouse gas emission source requiring calculation and reporting of emissions.

In §98.30(a), EPA has not defined "incinerator." Without a definition, it could apply to a very broad range of things from large waste incinerators to small thermal control devices for vent gas streams. While it may be appropriate to include non-hazardous waste incinerators due to the potential significant contribution to a facility's total GHG emissions, small devices may not be flow monitored and do not add a significant contribution to the total greenhouse gas inventory. It would be overly burdensome and unnecessarily costly to add these flow measurement devices to these sources to facilitate emission calculations.

It is not clear whether EPA intended for facilities to report greenhouse gas emissions of hazardous waste burned in hazardous waste incinerators or combustors. For example, Table C-1 (74 FR 16481) does not mention hazardous waste fuels. ACC recommends that EPA exempt hazardous waste combustion units from the rule. These hazardous waste units would be small contributions to the total inventory and may vary widely in flow rate and composition, thus making the calculations more difficult. Furthermore, EPA has recognized the small contribution by exempting hazardous waste from the calculations and reporting in the landfill subpart of this proposed rule.

Emergency Generators

EPA has requested comment on whether a permit should be required for emergency generators excluded from greenhouse gas reporting requirements in §98.3(b). ACC agrees with EPA that the reporting of GHG emissions from emergency generators is not necessary. This is supported by their infrequent use and small contribution to the total greenhouse gas inventory.

However, in §98.30(b), ACC does not believe that designation as an emergency generator in a permit should be necessary to exclude them from reporting. Some emergency generators might not be designated as “emergency” in their air permit even though they are for emergency use. Further, some may not be permitted at all. How the emissions from these generators are authorized will vary from state to state, depending on the details of state programs. For example, Indiana does not permit emergency generators at all, but rather considers them to be *de minimis*. Texas might cover them under a PBR (Permit by Rule). EPA should allow additional alternatives for omitting reporting for an emergency generator other than description in an air permit, such as hours of use and type of use. The emissions from emergency generators are very small compared to other stationary fuel combustion sources, and are insignificant compared to the inventory of greenhouse gases; therefore, discounting these emissions will not have a significant impact on the usefulness of the greenhouse gas inventory.

Also in §98.30(b), the term “emergency generators” should be changed to “emergency stationary RICE.” Many facilities use combustion units (e.g., diesel engines) as the motive force for pumps, to ensure fire water availability and process fluid movement during power outages. ACC recommends that EPA exclude all emergency stationary reciprocating internal combustion engines (RICE) as the term is defined in 40 CFR 63 Subpart ZZZZ (§63.6675). These are sources whose operation is limited to emergency situations and whose emissions are negligible when compared to other stationary combustion sources. Exclusion of these sources would exclude sources such as stationary RICE used to pump water in the case of fire or flood, for example.

For the reasons above, ACC recommends that EPA revise §98.30(b) to read as follows:

(b) This source category does not include portable equipment or ~~generating units that are designated as emergency generators~~ emergency stationary reciprocating internal combustion engines ~~in a permit issued by a state or local air pollution control agency.~~

GHGs to report - §98.32

The text of §98.32 should be revised by adding text to the end of the sentence as follows (new language underlined):

“...each stationary fuel combustion unit except as allowed by §98.36(c).”

Calculating Greenhouse Gas Emissions - §98.33

Stationary fuel combustion source emissions calculation methods require use of annual fuel consumption from company records. Specific alternative methods of determining fuel consumption are not spelled out, but it is assumed and hoped that the covered entities would have considerable flexibility in determining the annual fuel consumption. The following is but one example of the complications of determining fuel use. For many solid fuel fired units, such as stoker coal fired boilers and pulverized coal fired boilers utilizing volumetric coal feeders, there is no way to measure weight rate of coal feed to the boilers. In those cases, alternative methods of determining heat input and annual fuel consumption need to be used. For example, the Tier 2 methodology for MSW fired units allows for use of boiler steam output and the maximum rated heat input to design steam output ratio to determine heat input. A similar approach could also be used for other solid fuel fired units. Similarly, in cases where byproduct fuels are fired or co-fired, the covered entity should have latitude to utilize any methods appropriate for the unit that provide representative determination of CO₂ emissions. Providing flexibility in fuel consumption determination methodology will decrease the cost of the reporting program with an insignificant impact on overall emissions accounting accuracy. It is assumed that this is EPA's intention based on the reference to relying on company records.

EPA has requested comment on integrating fuel supplier requirement for HHVs and carbon content for Tier 1 and Tier 2 methodologies, which was not proposed. ACC recommends that EPA should require that the fuel supplier provide data for measured HHV and carbon content for all fuels in commerce. Requiring the fuel supplier to provide this information instead of the fuel users eliminates unnecessary duplication of analysis of the same fuel by multiple users. For example, one fuel supplier might supply many units within an industrial area, and requiring the fuel supplier to provide the data would reduce the number of required analyses correspondingly. In addition, when making this change, EPA should then alter the requirements in §§98.34(c) and (d) such that operators of stationary combustion devices do not need to obtain fuel analytical data when it is required to be provided by the fuel supplier.

In §§98.33(a)(3) and (b)(4), units may not have measured fuel flow rates and flow measuring devices may not be installed. Installing this equipment in a short period of time may be impossible due to long equipment delivery times, competition for purchasing measuring devices at the same time and among the many entities subject to the greenhouse gas reporting requirements, and timing of outages of process units required to install the equipment. Many of these process units would not normally be taken out of service for three to five years. Such outages would be unnecessarily costly. EPA should allow an additional five years or at the next scheduled maintenance turnaround shutdown after December 2009 for facilities to install the required flow meters, whichever is later. In the interim, in lieu of measured flow rates, facilities

should be allowed to use engineering calculations to determine flows. In addition, calculation of Part 75 F factors should be allowed in Tier 3 as allowed in Tier 4.

In §98.33(a)(3)(iii), the proposed Tier 3 methodology for a gaseous fuel requires the use of Equation C-5, which contains the term MVC. MVC is defined as the molar volume conversion factor and is stated to be equal to 849.5 scf per kg-mole at standard conditions for this equation and also throughout the rule. However, in §98.6, Definitions, EPA defines the term "Standard Conditions or Standard Temperature and Pressure" as meaning 60 degrees F and 14.7 psia. Using a temperature of 60° F, molar volume is calculated to be $(10.73)(520)/(14.7) = 379.6$ scf/lb-mole $\times 2.2 = 835$ scf/kg-mole. Thus, there appears to be a discrepancy between the standard conditions in the definitions and the standard conditions for the conversion factor in Equation C-5. It appears EPA may have used a temperature of 68 °F to obtain a molar volume of 849.5 scf/kg-mole. Thus, the molar volume that is required to be used doesn't match with a standard temperature of 60 °F. EPA could either revise the molar volume to closer to 835 or revise the definition of Standard Conditions to reflect a temperature of 68 °F.

In §98.33(a)(4)(i), EPA refers in this section to paragraph (a)(1)(iv)(D) of this section; however, this reference does not appear to exist in the proposed rule and EPA needs to correct this reference.

The Tier 4 calculation methodology requires a "stack gas volumetric flow rate monitor" (§98.33(a)(4)(i)). Many existing CEMS systems determine stack gas flow rate through methods other than direct measurement of the exhaust stream. The requirement to install volumetric flow rate monitors introduces an unnecessary cost and in many cases requires a complete redesign of the stack in order to position a meter properly. The final rule should allow calculation of the stack gas flow rate based on other methodologies. One method that should be allowed involves calculation of the stack flow based on measurement of the oxygen concentration in the stack, fuel flows, and temperature. Another method involves applying an air feed to exhaust flow ratio established through testing. This improvement will encourage facilities that have non CO₂ CEMS systems currently in place to enhance their system to measure CO₂. Requiring a stack gas volumetric flow rate monitor in order to use a CO₂ CEMS is a significant deterrent from voluntary use of the Tier 4 method.

In §98.33(b)(1), we believe that it is unnecessarily restrictive to limit the use of Tier 1 to units \leq 250 mmBTU/hr in size. EPA has not provided an explanation for this restriction and we recommend that it be deleted in the final rule. The variations introduced in the calculations will be very small compared to the size of the entire greenhouse gas inventory.

Section 98.33(b)(5)(ii)(E) does not specify that the CEMS installed must be a CEMS for monitoring CO₂. ACC believes that EPA meant a CO₂ analyzer, and should specify accordingly to eliminate any uncertainty. If EPA meant any CEMS monitoring device regardless of the CEMS ability to monitor CO₂ without additional equipment modification and possibly equipment purchase, then we recommend that EPA change the requirement to apply to existing CO₂ CEMS only. Requiring the added capability to monitor for other constituents is unnecessarily costly and not necessary for ensuring an appropriate level of accuracy for purposes of compiling an inventory.

Tier 4 Methodology

The criteria for when Tier 4 is required are confusing as written and we cannot determine whether it is only required for MSW or solid fuel, or if it applies to other large (≥ 250 MMBtu/hr) combustion units with liquid or gaseous fuels. In addition, the other criteria for MSW and solid fuels listed in Tier 4 are also confusing.

We recommend that EPA clarify the Tier 4 requirements as follows:

- Incorporate Table C-1 from page 16481 of the Federal Register containing the Preamble into the actual final rule.
- Include the following excerpt from Page 16483 of the preamble into the final rule, “The Tier 4 method, and the use of CEMS (with any required monitored upgrades) is required for solid fossil fuel-fired units with a maximum heat input capacity greater than 250 MMBtu/hr (and for units with a capacity greater than 250 tons per day of MSW).”
- In §98.33(b)(5)(ii), include the word “and” at the end of each item (A) through (F) to clarify that each one is required and that EPA did not mean “or” between these items.
- In §98.33(b)(5)(iii), include the word “and” at the end of each item (A) through (C) to clarify that each one is required and that EPA did not mean “or” between these items.

There may be additional ways to improve the clarity of the applicability of the Tier 4 measuring requirements in §98.33(b)(5). ACC encourages EPA to find additional ways to improve the clarity of this alternative. It is important that facilities be able to interpret this part easily due to the costliness of installing and operating the CEMS equipment.

Additional Clarifications

EPA has requested comment on the use of more technology-specific CH₄ and N₂O emission factors that could be applied in unit-level calculations for §98.33(c). ACC recommends that EPA eliminate CH₄ and N₂O calculations entirely due to their negligible impact on the total greenhouse gas inventory and on a facility’s emissions. In §98.33(c), according to the formulae provided, less than 0.00001 percent of the greenhouse gas emissions would be CH₄ or N₂O. Therefore, EPA should not require calculation and reporting of these emissions because their contribution to the total is insignificant.

Section 98.33(c)(4) refers to Table C-4; however, there is no Table C-4. The correct reference appears to be Table C-3.

In §98.33(c)(4), it is not clear what EPA would be approving. As written, it appears that EPA would approve whether a company can develop its own site-specific emission factors (EFs); however, if no EFs are provided for its site-specific or unit-specific fuels, the company must calculate its own EFs. Thus, no EPA approval should be required. A more appropriate approach

would be that EPA may audit a site's specific EFs for calculation validity. Furthermore, source testing will be an unwarranted cost to determine a very small emission factor. Either EPA should exclude these emissions from the reporting requirements or allow the owner/operator to estimate these emissions based on other factors and engineering estimations when the fuel combusted is not specifically listed in Table C-3.

Monitoring and QA/QC Requirements - §98.34

Sampling and Data Requirements

For §§98.34(c)(1) and (d)(3), the composition of natural gas does not change often enough to warrant monthly sampling. At most, ACC recommends annual sampling. ACC recommends eliminating the source sampling and testing of fuels, including pipeline natural gas supplies, to reduce the excessive burden of each facility needing to sample and analyze the fuel when instead it could be more efficiently sampled and analyzed only once by the supplier. Additionally, the sampling frequency should be yearly or whenever the supplier changes the source of the fuel such that the fuel composition may be likely to change. These fuels will not appreciably change in composition from month to month. As an alternative, requiring these fuels to be sampled twice per year would align with many custom fuel sampling schedules for determining sulfur content of natural gas.

Sections 98.34(c) and 98.34(d)(3) require routine measurement of the HHV and carbon content of fuels, respectively. The reporter should be allowed to use fuel specifications that include, but are not limited to, regulatory requirements, data provided by fuel suppliers, and specifications set by the reporter to determine HHV and carbon content. The frequency for determining HHV or carbon content from data obtained from a fuel supplier should be the same frequency for obtaining the data from the supplier. Also similar to other Clean Air Act rules, the final rule should include an option to decrease the frequency of sampling to annually if several consecutive measurements show minimum variation in the HHV or carbon contents.

For the sampling requirements of §98.34(c) and (d)(3), EPA should allow sufficient time until the next scheduled process unit turnaround or December 2009, whichever is later, for installing sample taps or locations in order to collect the samples for carbon analysis, molecular weight determinations, and high heating value. These sampling locations may not exist today. Facilities should not be required to incur the cost of additional process unit shutdowns to install these taps, and in most cases, scheduled shutdowns will occur on a three to five year cycle.

Calibration

In §98.34(d)(1), some flow meters may not be calibrated without shutting down the process. For example, in some cases, an orifice plate must be pulled out of the line to do a complete calibration. This might be part of manufacturer's recommendations as a part of calibration recommendations. It would not be practical to perform this yearly because equipment may not be out of service on a frequency of more than one time in every several years. The annual calibration should be limited to no more than would be required by Part 75 (electronic transmitter calibration) less the visual inspection every three years. In addition, for the reasons

cited above regarding possible unit shutdown for a full calibration per manufacturer's recommendations, it may not be practical or possible to complete all required calibrations between now and January 1, 2010. ACC recommends that EPA allow owners/operators to continue utilizing existing flow meters until the next scheduled shutdown for calibration, if it requires a process unit shutdown.

Further, in §98.34(d)(1), a facility might be purchasing different components from different manufacturers, e.g. the dP cell manufacturer might differ from the orifice manufacturer. It might, therefore, be difficult to follow the manufacturer's recommendations because different manufacturers might have recommendations in conflict with each other.

Also in §98.34(d)(1), some meter warranties may be voided if an attempt is made to calibrate them. In such a situation, EPA should allow for a facility to follow the manufacturer's recommendations or specifications.

Based on all of the above constraints and concerns, ACC recommends that in §98.34(d)(1), EPA require meter calibration at the lesser of the manufacturer's recommendations or annually or, alternatively, to calibrate on an alternate frequency determined to be appropriate through operating experience for the meter or based on other engineering analyses. This will address facilities whose flow measurement device manufacturers do not recommend periodic calibration and will also address other concerns noted in the proposed frequency.

Other issues

In §98.34(d)(3), facilities using process gas should be provided with an option to perform a statistical analysis to determine a sample and analytical frequency that is less often than daily, based on the potential for variations in process gas composition. Requiring daily sampling for all process fuels may be unnecessary. At a minimum, facilities should be allowed the option of initially sampling monthly and then using a different frequency if warranted by a statistical analysis.

In §98.34(e)(1)(i), (ii), and (iii), the terms are redundant if it is presumed they are connected by "and." EPA should clarify this by connecting each of the terms (i), (ii), and (iii) by "or."

No place in §98.34 does EPA provide a specified recommended methodology for measuring solid fuels. Requiring measurement of the fuel rate instead of allowing calculation would be especially burdensome and unnecessarily costly, and would require the installation of weighing equipment. Some sites currently calculate the amount of solid fuel combusted based on, for example in the case of a boiler, the amount of steam generated each month and the boiler efficiency. EPA should continue to allow such engineering calculations for solid fuel flow rate.

Data Requirements §98.35

We recommend that EPA modify §98.35 to allow the "best available estimate" method of §98.35(2) to be available for all parameters including those listed in §98.35(1), not just the limited parameters listed in §98.35(2), if the owner or operator can justify using it based on

process or operating knowledge. There may be times when the arithmetic averaging method does not yield an appropriate result, given variations in operating conditions.

In §98.36(b) and (c), EPA should modify these sections to allow a facility to report only the total CO₂ for a facility instead of unit-specific calculation and reporting. This is advantageous to the Agency as an inventory calculation tool because it will capture smaller sources and make the total inventory more complete. Many facilities do not have the meters required to do unit-by-unit calculations. Such calculations would be burdensome and excessive and would not add to the overall use of the information to develop a greenhouse gas inventory.

Examples illustrating this concern include:

- Natural gas is only metered where it enters the site. Therefore, EPA should allow calculation and reporting of site wide CO₂e. Although combustion unit specific emissions would not be reported, the inventory of CO₂ emissions from natural gas combustion at the site would be more complete and thorough than as currently proposed in Subpart C.
- The only record of fuel oil usage may be the amount delivered to the site. Some fuel oil is used in emergency engines. Since emergency engine use cannot be readily separated from the total consumption, the inventory of CO₂ emissions from fuel oil combustion at the site would be more complete and thorough than as currently proposed in Subpart C.

For §98.36(b) and (c), there are situations when the fuel-type might be CBI. In these instances, facilities will not want to report their fuel type, and EPA should not require it to be reported. This is especially true for §98.36(b)(5) for hydrogen production.

As an alternate to requiring each individual fuel type to be reported, ACC recommends limiting the reporting to the following categories: liquid, other solid fuels, MSW, biomass, natural gas, and other gaseous fuels [see Table C-1 in Preamble].

In §98.36(c), ACC supports all of the alternative calculation methods allowing unit aggregation that EPA has provided.

In §98.36(c)(3), there are certain situations where using the common pipe method will severely overstate the greenhouse gas emissions such as when natural gas is used as a feedstock for manufacturing processes instead of as a fuel. In these cases, EPA should allow the use of engineering calculations in lieu of measured flow rates within the common pipe method.

The Acid Rain regulation does not require reporting CO₂ by fuel if a CEMS is present, and this rule should not require CO₂ by fuels in any part of §98.36.

In §98.36, EPA does not appear to have limited the reporting by fuel type, even with CEMS being used. However, EPA must do so by changing the rule to allow aggregating fuel types at least when CEMS are used, because CEMS do not allow separating CO₂ emissions by fuel type if different fuels are burned at the same time. An example would be process gas fuel that is supplemented with natural gas.

In §98.36(d), the verification data is far greater than that required by any other rule. Instead of submitting this data annually and requiring excessive reporting, ACC recommends that facilities should be required to maintain this data and produce it upon request. In §98.36(d)(1)(i) requirements for verification data for Tier 3 methodology, where a process gas is being combusted, the submittal of daily data on quantity of fuel combusted, carbon content of the fuel, and molecular weight of the fuel is excessive. ACC recommends that monthly sampling be allowed unless and until a facility can show through a statistical analysis that a different and possibly less frequent sampling analysis may be appropriate. Further, these results should be shifted over to §98.37 Recordkeeping instead of requiring submittal of daily (or monthly) information for each of the variables used in the Tier 3 calculation methodology. At the most, EPA should not require reporting of more data than of monthly averages.

In §98.36(d)(1)(iv)(F), reporting RATA results is also overly burdensome. At most, EPA should only require reporting the RATA as a pass/fail result. RATA results will need to be reported for some other regulatory requirement for which the CEMS was installed, so the additional reporting here is redundant. These reports will be available onsite in the records as a result of other regulation, so there is no need to report or collect as part of this effort. Other CEMS requirements do not require transmitting the RATA report, only to verify that the RATA was done.

There is a reference to equation C-14 in both §98.36(d)(1)(vii)(D) and (E). We believe that reference is incorrect. The correct reference should be to equation C-13.

Tables

In Table C-1 of Subpart C, under the heading of "Petroleum Products" there is a listing for "LPG (energy use)". There is no definition of "LPG" in §98.6. However, there is a definition of "liquefied natural gas (LNG)" in §98.6, but that fuel is not listed in any of the Tables in Subpart C.

In Table C-1 of Subpart C, under the heading of "Petroleum Products" there are listings for "Aviation gasoline" and "Jet fuel". These terms also appear in Table C-3. Neither of these terms is defined in §98.6. However, "Kerosene-type jet fuel" is defined in §98.6, but that term is not used in Subpart C. EPA should clarify its use of these three terms in the proposed rules.

In Table C-1 of Subpart C, under the heading of "Petroleum Products" there is a listing for "Natural Gasoline" with a default HHV of 0.110. It would at first appear that "natural gas" is intended, but that fuel appears elsewhere in Table C-1. "Motor gasoline" also appears under this heading in Table C-1, but neither that term nor "natural gasoline" is defined in §98.6 and neither appears in Table C-3 of Subpart C, where the term "gasoline" does appear. "Gasoline" is not defined in §98.6. ACC suggests that EPA add definitions of "gasoline," "natural gasoline" and "motor gasoline" to §98.6. The headings "Biomass-derived Fuels (solid)" and "Biomass-derived Fuels (Gas)" appear in Table C-1. Listed under the heading "Biomass-derived Fuels (solid)" is the phrase "Wood and Wood waste (12% moisture content) or other solid biomass-derived fuels". Table C-3 contains the terms "Other Biomass" and "Wood and Wood Waste," without a

moisture content qualifier, but that table does not include a gaseous biomass-derived fuel entry. EPA should clarify its intent when using the "Biomass" terms.

There is an entry for "Landfill gas" in Table C-3 of Subpart C and that term is defined in §98.6. However, there is no entry for "Landfill gas" in either Tables C-1 or C-2.

It is difficult to match the "fuel types" listed in Table C-3 to the "fuel types" listed in Tables C-1 and C-2. This results because there are "fuel types" in Tables C-1 and C-2 that do not readily appear to have a counterpart "fuel type" in Table C-3. Examples are "coke," "ethane," "petrochemical feedstocks," "unfinished oils," "plastics" and "solvents" among others. Does this imply that reporting entities do not need to report Table C-3 emissions from these fuel types? There are also "fuel types" in Table C-3 that do not appear to have a counterpart "fuel type" in Tables C-1 and C-2. Examples are "digester gas," "landfill gas," "natural gas liquids" and "refinery gas."

There appears to be a typographical error in Table C-3. The word "Tites" is possibly a misspelling of the word "Tires."

D. Electricity Generation –Subpart D

Definition of the source category - §98.40

As we discussed earlier in §98.30(b), ACC recommends that EPA change §98.40(b) to read as follows:

(b) This source category does not include portable equipment or ~~generating units that are designated as emergency generators~~ emergency stationary reciprocating internal combustion engines, ~~in a permit issued by a state or local air pollution control agency.~~

As we discussed in Subpart C above, we are concerned that there is no *de minimis* level for small sources for this subpart (with the exception of portable units and emergency generators). For reference, a 5 MW gas turbine would emit about 25,000 CO₂e annually. Conversely, a utility-scale machine (GE Frame 7F or equivalent) might generate 750,000 MT tons of CO₂e annually. As currently proposed, both units – irrespective of their size – must be treated by the source in the same manner. A welding machine – if it is an EGU - would need to be treated similarly. Annual GHG emissions from such a machine would likely be less than a small car or truck. Irrespective of the size of the source, emissions must be calculated, data must be retained, emissions must be reported, etc. (See proposed 40 CFR 98.42, 43, 44 and 46.)

E. Fluorinated Greenhouse Gas Production – Subpart L

EPA should revise the perfluorocarbon (PFC) definition to indicate PFCs are compounds of carbon and fluorine and that all carbon bonds are fully saturated (only single bonds) where IPCC has identified a GWP; and the hydrofluorocarbon (HFC) definition to include only those liquid or gaseous (not including fluoropolymers) compounds containing between one and six hydrogen, fluorine, and carbon compounds identified by IPCC with a GWP.

Further, some facilities may produce fluorinated gases that are used as intermediates in subsequent chemical synthesis by our customers at their facilities, yielding a final product in which there are no emissions of the fluorinated compound of concern. EPA should exempt from reporting any fluorinated compounds that are not placed into subsequent emissive uses. This approach was taken in the ozone depleting substance program (40 CFR Part 82), where ozone depleting substances that are transformed in subsequent use to non-emissive compounds are exempt from the program.

Calculating GHG emissions - §98.123

The proposed rule states that GHG emissions from the production process over the period “p” shall be estimated at least daily using a mass-balance methodology. This shall be accomplished by monitoring:

- total mass of fluorinated GHGs produced over the period “p” estimated at least daily [§98.124(a)];
- total mass of each reactant fed into the production process measured at least daily [§98.124(b)];
- total mass of each reactant permanently removed from the production process measured at least daily [§98.124(c)];
- total mass of waste fed into a destruction device measured at least daily [§98.124(d)];
- mass flow of each process stream that contains more than trace concentrations of a by-product responsible for yield loss measured on a daily basis [§98.124(e)]; and,
- mass flow of each process stream that contains a fluorinated GHG by-product in more than trace concentrations measured on a daily basis [§98.124(f)].

Measurements shall be accomplished using flow meters, weigh scales, or a combination of volumetric and density measurements with an accuracy of 0.2% of full scale or better. All measurement devices shall be calibrated prior to the first reporting year and at least annually thereafter, while gas chromatographs shall be calibrated at least monthly.

However, fluorinated GHG production varies widely within the source category. EPA proposed a rule presuming that all fluorinated GHG manufacturing operations occur in continuous process units. While much of this source category consists of continuous process units, several batch or

campaign processes would be subject to proposed subpart L. ACC members operating continuous processes have indicated that because of process rate variations, seasonal changes in process operations, changing amounts of raw materials and products in various process steps, and instrument variability, continuous process operators would struggle to meet the requested mass balance approach using existing or modified technology. Attempting to invoke a mass balance requirement on batch operations, with varying batch sizes, quantities and compositions of various process streams, and required variability to manufacturer specific batches to a wide variety of product specifications makes compliance with any mass balance approach effectively impossible.

In the Technical Support Document for the Fluorinated GHG Production Source Category, EPA identified, justified, and dismissed the traditional process vent emissions estimation method predominantly used in the Fluorinated GHG source category. Fluorinated GHG manufacturers have, for other Clean Air Act compliance reasons, invested in and developed comprehensive emissions estimation systems based on tracking criteria and hazardous air pollutants that can be extended to include industrial GHG emissions far more cost-effectively than any mass-balance approach that at best would not accurately emissions, at worst would be impossible to implement. Therefore, ACC recommends that EPA require, or at least provide as an option, fluorinated GHG manufacturers to utilize the process vent monitoring system described in TSD Section 3.c. for GHG reporting obligations. In addition, EPA should explicitly cross-reference existing compliance obligations under 40 CFR 51, 52, 60, 61, 63, 64, 65, 70, 71, and 75 as appropriate compliance methods for process units impacted by one or more of these requirements.

Monitoring and QA/QA requirements - §98.124

Section 98.124(3)(e) requires that the mass flow of each process stream that contains more than trace concentrations of a by-product responsible for yield loss be measured on a daily basis. An ACC member company who operates the largest NF_3 manufacturing facility in the U.S. does measure reactor vent flows; however, process driers and absorbers which vent to caustic scrubbers for HF control are not measured. The composition and mass flow rates for these vents were originally estimated using process chemistry, mass-balance and accepted emission rates. The estimates were then used to design the caustic scrubbers, as well as their operation and maintenance regime. ACC recommends engineering estimates based on process knowledge be an acceptable alternative to the use of measurement instrumentation for these process streams.

The mass balance approach that EPA indicated as a no-cost emission estimation method is overly complex and unnecessary for the industrial GHG manufacturing source category. The proposed rule requires that scales, flow meters and other measuring instrumentation must have accuracy and precision of 0.2%, which essentially prescribes the use of Coriolis flow meters for streams where Coriolis meters may be appropriate. As recognized by the Agency in the Technical Support Documents regarding fluorinated GHGs, Coriolis flow meters are expensive (i.e., GE Rheonik RHM Series Mass Flow Meters prices start from \$2,473 to \$18,188, with accessory transmitter prices starting at \$3,713.). This cost does not address the cost of installation and probable production equipment modifications, which typically equal or exceed the purchase cost, nor the emissions associated with shutdown and start-up to install the new meters. The 0.2%

accuracy levels expected in subpart L are not achievable across an entire chemical manufacturing process unit, even on an annual basis. Many in-process streams in this source category are not compatible with Coriolis meters. Coriolis meters capably measure consistent liquid-phase streams or very small gas-phase streams, but are incapable of measuring dual-phase streams typical of fluorochemical manufacturing. EPA cites the 0.2% accuracy value that is typical for Coriolis meters in liquid service and does not specify the 1% accuracy typical of the same meter in gas service. Many instruments in use today are not capable of this level of accuracy, are not capable of any calibration due to the lack of user serviceable parts, or are not installed in all of the locations required to provide a complete unit mass balance. Industrial GHG manufacturers typically do not use daily mass balance data to evaluate emissions today. One member company estimated that to retrofit industrial GHG manufacturing facility to meet the proposed data quality standards would cost \$25 million in capital cost and \$3 million per year in annual costs. Member companies should be provided the option to use existing emission estimation tools to provide a cost-efficient industrial GHG emission report.

Mandated annual calibration of all flow meters, scales, load cells and volumetric and density measures used to measure production parameters is inconsistent with accepted engineering principles and manufacturer-required practices to maintain equipment warranties. Empirical data collected throughout routine operations, as well as preventative and corrective maintenance, is used to determine equipment performance and reliability. This in turn is utilized over time to refine calibration and maintenance requirements and schedules. An arbitrary annual calibration requirement defeats the value of this knowledge, and it ultimately adds cost, promotes premature equipment failure, and increases emissions due to unnecessary shutdowns and start-ups. ACC recommends that an initial calibration or manufacturer calibration warranty be required for all new and replacement measurement equipment and on-going calibration be based upon a schedule determined by the facility considering operational data and manufacturer specifications.

The analytical burden associated with completing this material analysis could be enormous for some facilities where numerous "non-emission" streams would require daily analysis solely for the purpose of completing the material analysis. For example, byproducts and reactants may be present in many individual process streams. These could include organic and inorganic materials and which require daily analysis. In some cases, more frequent analysis of batch process streams would be required in order to insure that samples were representative. One ACC member company has determined that multiple analytical instruments would be required for many individual samples, including NMR, GSMS, and GC for complete characterization of a single sample. The analytical costs for one facility alone were estimated to exceed \$25 million per year.

EPA does not adequately define the "trace amount" concept at proposed §98.124(c). Given the precision being called for in the metering and measurements involved, we request a clarification on how to determine trace amounts on a yearly basis. Are these amounts measured as a part of the process during operation or are they below detection limits? This is important because any stream with more than a "trace" amount requires a flow meter for measurement analytical testing on a periodic frequency to determine composition of the stream with respect to GHGs and the above requirements for QA/QC precision and accuracy apply.

EPA should not require annual stack testing for this source category. Subpart L reporters are typically heavily regulated under existing Clean Air Act provisions, and should be allowed to use existing stack testing requirements to demonstrate actual emission rates and destruction and removal efficiency (DRE) values for GHG reporting. Some members are required to conduct periodic testing for other Clean Air Act requirements, and should be allowed to modify these test protocols to incorporate required steps to obtain Part 98 data. Other members, not subject to periodic testing on all Part 98 vents, should have the option to develop appropriate emission factors, based either on the EPA emission factor development guidance for continuous processes or the Pharmaceutical NESHAP batch emission calculation method in 40 CFR 63.1257(d) for batch processes, as appropriate, in lieu of annual testing. Stack tests for each stack cost approximately \$10,000 per year per vent, and should only be required if no data exists for that process unit.

ACC is concerned that for many applications, analytical limitations would severely limit the integrity of the material balance approach. For many industries, the material balance method has not been adequately demonstrated as an emissions estimation method and EPA has no assurance that the reported values will result in accurate emission estimates. Specific concerns are representative sampling, sample complexity, co-elution of analytes, and the lack of analytical methodologies for certain matrices.

Procedures for estimating missing data - §98.125

The proposed rule states that substitute data for missing quality-assured parameters shall be either a secondary measurement for mass and flow measurements, or the arithmetic average of parameter values immediately preceding and following the missing data. If the methods described in §§98.125(a)(1) and 98.125(a)(2) are likely to under- or over-estimate the parameter value, a best estimate shall be developed with documentation on the methods used, and rationale and reasons to explain why (a)(1) and (a)(2) would under- or over-estimate the parameter.

While missing and/or suspected erroneous data is undesirable, it is not uncommon at complex manufacturing facilities. The methodology proposed for substitute data is an unusually burdensome requirement that will not materially change overall emissions validity. Furthermore, efforts required by this prescribed methodology and associated documentation add labor cost which can be better applied to correcting the cause of the missing data.

EPA has already addressed this issue in the Compliance Assurance Monitoring (CAM) rule at 40 CFR Part 64, and in the Maximum Achievable Control Technology (MACT) standards at 40 CFR 63 Subpart SS. Both of these systems require affected sources to evaluate hourly data, determine that the data is valid, and average valid hourly data to determine daily compliance values for each required parameter. This system has served EPA well in the ten years since CAM and subpart SS have been in effect. Most fluorochemical manufacturing units that would become subject to subpart L are regulated using one or both of these data management systems, which require requisite data quality, instrument calibration, and maintenance standards. EPA should not use a reporting rule to override or conflict with existing data management obligations,

but should instead determine, for all Part 98 subparts, that compliance with any existing Clean Air Act data management system is compliance for any Part 98 data management requirement.

Data reporting requirements - §98.126

The proposed rule requires reporting of total mass of fluorinated GHG produced, total mass of each reactant fed into the production process, total mass of each reactant permanently removed from the production process, total mass of the fluorinated GHG product removed from the production process and destroyed, mass of each by-product generated, mass of each by-product destroyed, mass of each by-product recaptured and mass of each fluorinated GHG emitted. Additionally, full explanation for the reason and length of time quality-assured parametric data was missing, and the information required by §98.125.

ACC believes that the data that must be collected to complete the mass-balance calculations for the emissions estimate prescribed at §98.123 should not be required to be submitted. The Agency surely recognizes that this data is extremely sensitive and confidential business information, which can be utilized to deduce process costs, efficiencies and competitive strategies. In certain instances, this data can be proprietary or protected by patent. ACC recommends that rather than submitting any process information, except actual emissions, as part of the annual report, this data shall be maintained by the respective facility and available for review, if necessary, as provided in §98.3(f) and §98.127. In lieu of this data submission, the final rule should recognize and allow self-verification and certification similar to the Title V Operating Permit program where facilities represent their compliance with applicable regulations and permit requirements without submission of the detailed data supporting that certification.

Reporters who conduct activities in both subpart L and subpart O should be given the opportunity to report subpart O activities under subpart L. The overlapping and conflicting requirements of these subparts, with no petition process available to reporters who face dual reporting requirements for the same emission control device and process vent, need the flexibility to report under one consistent system. EPA should provide the option for subpart O reporters also subject to subpart L to consolidate reporting under subpart L.

Technical Support Document for Emissions From Production Of Fluorinated GHGS

In Section 3 of the Technical Support Document, EPA considers the following three methods for estimating fluorinated GHG emissions:

- Default emission factor (e.g., 1.5%) applied to the total fluorinated GHG production of the facility;
- Mass-balance using the difference between reactants, products, by-products and wastes to calculate fluorinated GHG emissions; or,

- Measurements of the composition and mass flow rate of gas streams actually vented to the atmosphere from fluorinated GHG production, either continuously or long enough to establish a representative emission factor.

Mass-balance was the methodology incorporated into the proposed rule.

ACC believes that all three reviewed methods should result in a representative total of industry-wide fluorinated GHG emissions. ACC recommends that all methods be afforded to the twelve facilities affected by Subpart L. This approach is least costly and avoids unnecessary shutdowns to incorporate new measurement equipment, while still capturing industry-wide emission totals. ACC further recommends that the final rule afford affected facilities the opportunity to submit for the Agency's consideration an alternative method from the three described in the Technical Support Document. This recommendation is consistent with facility-specific determinations accepted and practiced in other regulatory programs.

Section 3.b.1 of the Technical Support Document states that some fluorocarbons, such as HCFC-22, are produced by reaction an organic (carbon-containing) compound with HF, ultimately producing the fluorinated GHG and HCl. ACC recognizes that this is the process employed to produce many HFCs, HCFCs and some PFCs. However, this is not the process used by an ACC member company operating the largest NF_3 manufacturing facility in the U.S. ACC is concerned if only the process described noted above from the Technical Support Document was the basis for the requirements contained in Subpart L of the proposed rule, then Subpart L and Subpart OO do not adequately address the chemistry, equipment and practices employed by the NF_3 production industry. ACC recommends the Agency consider this concern when reviewing other NF_3 -related comments submitted herein.

In the Industrial GHG Manufacturing Technical Support Document, EPA describes three methods for industrial GHG manufacturers to calculate emissions: default emission factors, production unit mass balances, and process vent monitoring. On TSD Page 14, EPA incorrectly asserts that the mass balance approach is the industry standard. Several ACC members use the process vent monitoring approach identified in section 3.c. of the TSD to calculate emissions of regulated air pollutants that must be reported under existing Clean Air Act requirements. Coincidentally, several member facilities already calculate, or could readily calculate, emissions from industrial GHGs by utilizing or modifying the existing process vent calculation processes. ACC also recognizes that a process vent emission approach requires estimation of fugitive emissions from equipment components. EPA should, as suggested on TSD Page 14, allow reporters to utilize one of the fugitive emission estimation methods identified in *Protocol for Equipment Leak Estimates* (EPA-453/R-95-017) to calculate industrial GHG fugitive emissions. Facilities would choose between the default approach in Table 2-1, the leak/no-leak factors in Table 2-5, or the correlation equations in Table 2-9 of the *Protocol*, as appropriate, to calculate actual fugitive emissions.

F. HCFC-22 Production and HFC-23 Destruction – Subpart O

EPA should focus Subpart O on the destruction efficiency of HFC-23, not on the variety of other issues included in Subpart O, such as the leak detection and repair discussion more appropriately discussed in Subpart L. Facilities that have determined DRE for the destruction device using historical data should be authorized to utilize this information to determine removal. Production related Subpart O requirements at proposed §98.156(c) through (e), if necessary, should be standardized with modified Subpart L requirements described above, or all process activities should be regulated under a modified Subpart L.

G. Hydrogen Production – Subpart P

Definition of the source category - §98.160

EPA should clarify that this subpart is only applicable to commercial hydrogen production facilities, and not those units that incidentally produce hydrogen or hydrogen-containing byproduct gases that are typically combusted.

The proposed rule described the applicability of Subpart P as those hydrogen production facilities not owned or under the direct control of the refinery or other manufacturing operation owner or operator. The determination of control can, under some circumstances, be ambiguous. Under the California mandatory GHG reporting rule, further clarification on reporting responsibility was added to include a default provision that the entity that holds the air permit for the affected facility is the reporting entity. EPA needs to clarify the responsibility for reporting where the owner/operator may not hold the applicable air permit for an affected facility. ACC proposes that the operator of the hydrogen plant should assume the reporting responsibility.

GHGs to report - §98.162

The proposed rule describes the emission reporting obligation in §§98.162(a) and (b), separately, as the “CO₂ process emissions...” and “CO₂ ... emissions from the combustion of fuels...” respectively. It is not clear if EPA intended for these emissions to be reported separately or combined. In some emission calculation methods (most obviously in Tier 4 CEMS method), the calculation method does not distinguish between “process” CO₂ and “combustion” CO₂, so it is impractical to report these as separate, discrete emissions. Of even greater concern is the fact that through separate reporting of process vs. combustion CO₂ emissions, it is a relatively straightforward back-calculation to determine the process efficiency of the hydrogen production process. This is considered critical CBI that cannot be allowed to be revealed in reports accessible to domestic and international competitors and customers of the regulated source. ACC recommends that EPA should clarify the CO₂ emission reporting obligation as combined “process” and “combustion” CO₂ emissions, regardless of the calculation method employed. If

separate, discrete reporting of such emissions is actually required, provide explicit protection for this very critical confidential business information.

In §98.162(b), the proposed rule defines the emission calculation methods appropriate for hydrogen production facilities as those described in Subpart C for stationary combustion sources. Accordingly, all the comments made by ACC regarding the applicability of the various calculation method tiers under section §98.33(b) apply to this Subpart, as well. Of particular concern is the (mis-)applicability of the Tier 4 calculation methodology unless it is clarified that *all* of the conditions described in §§98.33(b)(5)(ii)(A), (B), (C) *and* (D) are necessary in order to trigger the Tier 4 method requirement.

We encourage EPA to be more flexible as it relates to the applicability to the alternate combustion emission calculation methods. In particular:

- Allow use of the Tier 1 method for units of any size (currently restricted to units <250 mm BTU/hr or less), particularly for standard fuels of commerce such as natural gas, LP gas and fuel oils, where billing-quality consumption data is accurate and readily available and the default HHV and CO₂ emission factors are well known constants (as noted in the Preamble for the proposed rule – natural gas carbon content is always within 1% of the default ratio).
- Recognize that a source's current practices of occasionally characterizing fuels for HHV or carbon content does not necessarily constitute having data "available" consistent with the compliance expectations of Tiers 2 and 3. Where Tiers 2 or 3 would be required, existing fuel characterization may not be according to the specified analytical methods or at the required frequency. Do not require Tier 2 or 3 where data fully meeting the defined compliance expectation is not currently being obtained.
- Do not require the use of the Tier 4 method where alternative fuel consumption data is available. Allow optional use of the Tier 4 method where, at the source's discretion. This may be a suitable calculation method where a source uses multiple fuels and/or non-commercial fuels or where existing CEMS systems include CO₂ measurement or can be modified at lower cost than alternative fuel consumption and/or characterization devices/practices. In any case, let the regulated source determine which method is most cost effective for their particular situation.

And,

- Clarify the requirement to employ the Tier 4 calculation method. Resolve the apparent discrepancy between the intent to limit Tier 4 to only Solid Fossil Fuel fired combustion units, per Table C-1 of the Preamble, with the actual imposition of Tier 4 described under §98.33(b)(5)(ii). Clarify that in order for Tier 4 to be required under §98.33(b)(5)(ii), all the conditions under §§98.33(b)(5)(ii)(A), (B), (C), and (D) must be met. Specifically, conditions (A), (B), (C), and (D) should be separated by the word "and" – absent that, an implied "or" would force this calculation method on many other combustion units for which it was not intended.

Further, do not require the use of the Tier 4 method where alternative fuel consumption data is available. Tiers 1, 2, and 3 offer viable alternatives for many combustion sources that will yield comparable (and in many cases more) accurate emission estimates. Allow optional use of the Tier 4 method where, at the source's discretion, this may be a suitable calculation method where a source uses multiple fuels and/or non-commercial fuels or where existing CEMS systems include CO₂ measurement or can be modified at lower cost than alternative fuel consumption and/or characterization devices/practices. In any case, let the regulated source determine which method is most cost effective for their particular situation.

Calculating GHG emissions - §98.163

The proposed rule provides specific equations (designated P-1, P-2, and P-3) under §§98.163(b)(1), (2), and (3) for calculating the process emissions arising from the feedstock consumption of hydrogen production. These equations do not recognize the situation where synthesis gas (a mixture of hydrogen and carbon monoxide) and/or carbon monoxide, itself, is a purposeful co-product of the reforming process to form hydrogen. In these instances, some of the feedstock carbon is not exiting the process as CO₂, but rather as CO, and therefore, a term should be added to the equation to reduce the apparent process emissions accordingly. This approach has been successfully defined under the California mandatory GHG reporting methodology for hydrogen plants, depicted as the "S" term in their equations under CA §§95114(b)(2) and (3)(B). EPA needs to correct equations P-1, P-2 and P-3 to account for feedstock carbon that does not exit the hydrogen production facility as CO₂.

In §98.164(c), the proposed rule indicates that a sample of feedstock must be collected and analyzed at least monthly. The language as written implies the regulated source will conduct the sampling and analysis. In many instances, feedstock characterization is conducted by the supplier of that feedstock, particularly when the feedstock is a standard hydrocarbon fuel of commerce (natural gas, LP gas, fuel oils, etc.) that is supplied to multiple consumers. In such instances, such feedstocks are more efficiently characterized by their suppliers than by their consumers.

In addition, the most common feedstock for hydrogen production is natural gas. As we commented previously (§§98.33(c) and (d)), and reiterated in the Preamble to the proposed rule, the carbon content of standard natural gas is well known and very consistent. Monthly characterization of natural gas is not necessary to develop a sufficiently accurate calculation of hydrogen process emissions.

EPA should allow the characterization of feedstocks (sampling and analysis) to be conducted by either the feedstock consumer (the regulated source) or the feedstock supplier. The characterization of standard fuels of commerce used as hydrogen production feedstocks, such as natural gas, should not be required since default values will yield a sufficiently accurate emission estimate. The characterization of such standard fuels of commerce used as feedstocks should be optional and at the source's discretion.

The proposed rule in §98.164(d) requires all fuel flow meters, gas composition meters and heating value monitors to be calibrated initially and annually, or at the meter manufacturer's specified frequency, thereafter. This requirement fails to recognize that some on-line measurement device installations do not allow calibration without taking the line out of service, thereby forcing a shutdown of the combustion/manufacturing process. In many instances, scheduled maintenance shutdowns for such equipment/processes will not occur on this prescribed frequency. Unless provisions are added to the proposed rule which provide relief from this required calibration frequency, manufacturing processes will be required to shutdown solely to complete the required calibration, resulting in significant cost, business disruption and, in many cases, increase environmental impacts from the inefficiencies of the start-up/shutdown activity. These issues are comparable to provisions under many EPA rules regarding the repair of leaking VOC fugitive emissions components where repair would require a process shutdown, and instead the repair deadline is extended to the next scheduled maintenance shutdown. The final rule should include provisions for an extension of the required meter/monitor calibration deadline (as well as the initial calibration, if appropriate) where the calibration would require removing the process line from service. The calibration requirement should then be extended to the next scheduled maintenance shutdown for the impacted unit/process.

Procedures for estimating missing data - §98.165

Section 98.165(a) prescribes methodology to substitute for missing data used in the emission calculations. For missing feedstock supply rates, the method prescribed is using the lesser of the maximum supply rate the unit is capable of processing or the maximum supply rate that the meter can measure. This approach is in contrast to the method prescribed for substitution for missing fuel consumption data under §98.35(b)(2), where the "best available estimate" is deemed an appropriate substitution. In many cases, use of valid data points before and after the unit, use of long-term consumption averages or estimates derived from other measured process data (e.g. production rate) can yield sufficiently accurate estimates to substitute for missing data. The data substitution method for missing feedstock supply rate data should be changed to be consistent with §98.35(b)(2), allowing use of the "best available estimate."

For missing feedstock carbon content data, however, the proposed rule does not offer any alternative to substitute appropriate alternate values for any missing data. The only option offered in the proposed rule for missing carbon content data under §98.165(b) is to perform a retest. This approach is in contrast to the method prescribed for substitution for missing fuel carbon content data under §98.35(b)(1), which averages before/after values to substitute for missing data. The data substitution method for missing feedstock carbon content data should be revised in §98.165(b) to be consistent with §98.35(b)(1), allowing use of the average before/after values.

Section 98.166(b) prescribes reporting requirements for annual feedstock consumption and annual hydrogen production. Such process and commercial data is considered critical and must not be revealed in reports accessible to domestic and international competitors and customers of the regulated source. As discussed earlier, ACC does not support the requirement to report confidential process and commercial data. If data must be reported, the reporting rules must provide explicit protection for this very critical confidential business information.

Data reporting requirements - §98.166

Section 98.166(c) prescribes reporting requirements for the feedstock carbon content. First, the requirement to report a monthly value for this data field is premised upon the need to characterize the feedstock on that frequency. As we stated in our comments on §98.164(c), monthly characterization for some standard hydrocarbon fuels of commerce (natural gas, LP gas, fuel oils, etc.) used as feedstock is not warranted, particularly for natural gas. Second, reporting this carbon content will provide information about the source and quality of the feedstocks used in the production process. Such process and commercial data is considered critical confidential business information that cannot be allowed to be revealed in reports accessible to domestic and international competitors and customers of the regulated source. Again, ACC does not support the requirement to report confidential process and commercial data. If data must be reported, the reporting rules must provide explicit protection for this very critical confidential business information.

H. Miscellaneous Uses of Carbonates – Subpart U

Definition of source category - §98.210

EPA has proposed to require GHG emissions reporting from any facility that meets the requirements of §98.2(a)(1) or (2) and that “uses” any carbonate in a manufacturing process. If interpreted literally, this language would require that any piece of equipment that has any amount of a carbonate compound would be subject to reporting if it meets the criteria of §98.2(a)(1) or (2). Because carbonate compounds are ubiquitous on earth,⁵ nearly every piece of equipment could conceivably meet this definition.

In addition, this language will require facilities with non-emissive uses of carbonate to analyze and report data. Clearly, this will impose costs on the economy without any environmental benefit. Examples of non-emissive uses of carbonates, all conducted at temperatures well below 1,000°F, include the following:

- Blending calcium carbonate (a.k.a. limestone) into an architectural coating material;
- Adding sodium carbonate (a.k.a. soda ash) to a wastewater treatment system for pH control;
- Adding calcium carbonate (a.k.a. agricultural lime) to a research field at an industrial facility;
- Blending calcium carbonate into road-building aggregate or applying road-building aggregate at an industrial facility;

⁵ United States Bureau of Mines. <http://www.absoluteastronomy.com/topics/Carbonate>.

- Blending dolomite into soil conditioners for distribution and sale;
- Adding sodium carbonate to a water softener system;
- Using sodium carbonate as a food additive for acidity control, dough conditioner, anti-caking agent, etc.;
- Using sodium carbonate as a toothpaste additive; and
- Adding sodium bicarbonate (a.k.a. baking soda) to a dough mixture.

EPA noted that “the multiple emissive and non-emissive uses of these carbonates may create confusion over which facilities are required to report.”⁶ However, EPA has not proposed language that would resolve this confusion. The language of §98.2(a)(1) or (2) requires any facility that has a listed category or that annually emits 25,000 metric tons or more of CO₂e to report its emissions from miscellaneous uses of carbonate. This means that a facility that has a large boiler would have to report data from non-emissive uses of carbonate, such as blending limestone into a building coating.

EPA discusses the fact that in some applications, “limestone undergoes a calcination process in which the limestone is sufficiently heated, generating CO₂ as a by-product.”⁷ However, the proposed language does not restrict reporting to this specific type of process, therein creating the confusion. In order for limestone or any other carbonate to dissociate CO₂, the CO₂ equilibrium pressure must exceed the partial pressure of CO₂ in the air. Based on the current CO₂ concentration in the atmosphere (360 ppmv),⁸ the atmospheric partial pressure is approximately 0.3 mmHg. Limestone has to be heated above 550°C (1,022°F)⁹ for the CO₂ equilibrium pressure to exceed the CO₂ partial pressure. Clearly, most “miscellaneous uses of carbonate” do not come close to these temperatures yet EPA has proposed no exemption for these facilities. According to §98.214, facilities that have no emissive uses of carbonate will still have to analyze their carbonate inputs and measure the calcination fraction annually. The only exception to the calcination fraction measurement is to assume that the fraction is 1.0 which is clearly inappropriate for these non-emissive uses.

We recommend that EPA modify the proposed language as follows (new language underlined):

§98.210(a) This source category consists of any equipment that uses limestone, dolomite, ankerite, magnesite, silerite, rhodochrosite, sodium carbonate, or any other carbonate in a manufacturing process where the carbonate is present at greater than 10% by weight and is heated to a temperature sufficient to make decomposition possible.

⁶ *Technical Support Document: Limestone and Dolomite Use*. USEPA Office of Air and Radiation. January 22, 2009. p. 6.

⁷ *Id.* at p. 3.

⁸ *Stabilization of Atmospheric Greenhouse Gases: Physical, Biological, and Socio-economic Implications*. Intergovernmental Panel on Climate Change, February 1997. Figure 1, p. 3.

⁹ *CRC Handbook of Chemistry and Physics*. CRC Press, Boca Raton, FL. 65th Edition – 1983. p. F-66.

Calculating GHG Emissions - §98.213

For those facilities that have emissive uses of carbonate, EPA should allow for an alternate measurement system in which the carbonate fraction of the products is measured instead of the calcination fraction. EPA has proposed to require the carbonate inputs based on standard emission factors. Clearly, EPA has confidence in the methodology, therefore, similar calculations for the carbonate outputs should also be acceptable.

The proposed language would be modified as follows (new language underlined):

§98.213 Calculate the process emissions of CO₂ following methodology specified in paragraph (a) or (b) using Equation U-1 of this section.

(a) [Existing language]

(b)

$$E_{\text{CO}_2} = [\sum (M_k * EF_k) - \sum (M_j * EF_j)] * 2000/2205 \quad (\text{Eq. U-2})$$

Where:

E_{CO2} = Annual CO₂ mass emission from consumption of carbonates (metric tons)

M_k = Annual mass of input carbonate type k (tons)

EF_k = Emission factor for the carbonate type k, as specified in Table U-1 to this subpart (metric tons CO₂/metric ton carbonate input)

M_j = Annual mass of output carbonate type j (tons)

EF_j = Emission factor for the carbonate type k, as specified in Table U-1 to this subpart (metric tons CO₂/metric ton carbonate input)

§98.216

(a) [Unchanged]

(b) If following §98.213(a):

- a. Annual carbonate consumption (by carbonate type in tons)
- b. Annual fraction calcinations

(c) If following §98.213(b):

- a. Annual carbonate input (by carbonate type, in tons)
- b. Annual carbonate output (by carbonate type, in tons)

(d) [Unchanged]

Recordkeeping- §98.217

The records that EPA has proposed to require are duplicative and therefore place unnecessary costs on the economy with no added environmental benefit. In §98.217(a), EPA proposes to require that facilities maintain records of monthly carbonate consumption including procedures used to ensure accuracy. Then in §98.217(c), EPA proposes to require that facilities maintain

records of all carbonate purchases and deliveries which does not provide any information additional to §98.217(a). We therefore encourage EPA to delete §98.217(c) in the final rule.

I. Nitric Acid Production – Subpart V

Monitoring and QA/OC requirements - §98.224

Section 98.224(a) requires at least annual performance testing and calculation of a site specific emission factor. It also requires additional performance tests whenever the production rate is changed by more than 10 percent from the production rate measured during the most recent performance test.

The proposed requirement for the additional testing is problematic and impractical for several reasons:

- The proposed rule does not account for rates varying during start up and shutdown. As written, it could be interpreted that performance tests are required for each 10% increment from zero to 100% capacity.
- It is not uncommon for production rates to vary by more than 10% many times over a year.
- The 10% production change is relative only to the most recent performance test, which could result in a significant and unwarranted number of performance tests. For example a facility may conduct a performance test at 100% capacity. During the next month, the facility may reduce its rates down to 90% to control inventory, requiring a new performance test. If the rates are increased back to 100% the following month, then yet another performance test would be required as the rates are more than 10% from the most recent performance test.

It is suggested that this section be changed to allow up to 15% change in operating rates before a new performance test is required. Additionally, retesting should not be required if a performance test within 15% of the new rate has been conducted during the last 12 months.

Below is suggested language for §98.224(a): (new language underlined)

You must conduct a performance test and calculate a new emissions factor at least annually. You must also conduct a new performance test whenever the production rate of a production line is changed by more than 15% from the production rate measured during a performance test conducted during the previous 12 months, provided a significant process modification has not occurred. The new emissions factor may be calculated using all available performance test data (i.e. averaged with the data from previous years), except where process modifications have occurred or operating conditions have

changed. Only the data consistent with the period after the changes were implemented shall be used.

Data Reporting Requirements - §98.226

Section 98.226 lists specific data reporting requirements for nitric acid facilities. Annual production rates, capacity and operating hours are clearly CBI and would need to be classified as such. It is recommended that these items be removed from this section and only be required to be retained by the facilities and made available for review by EPA and the states.

J. Petrochemical Production – Subpart X

Definition of the source category - §98.240

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

Reporting Threshold - §98.241

Section 98.241 states that Subpart X is applicable if the facility contains a petrochemical production process and the facility meets the requirements of either §98.2(a)(1) or (2). The second part of this applicability statement in §98.241 is redundant and potentially confusing because §98.2(a)(1) states that the reporting requirements apply to any facility that contains a petrochemical production source category. We therefore recommend that it be clarified or deleted.

Calculating GHG Emissions - §98.243

Ethylene Units

Section 98.243 requires process-based GHG emissions to be determined based on either a continuous emission monitoring system or by conducting a weekly mass balance for each process unit. These proposed methods are not appropriate for ethylene units which, as determined by EPA in the Ethylene NESHAP rulemaking, do not have continuous process vents. These units typically do not have CEMS, and the proposed alternative, a weekly mass balance requirement, is an onerous undertaking considering the relatively small amount of GHG emissions. We offer the following example to illustrate the concern: For every 100,000 pounds of ethylene produced, there could be as much as 300,000 pounds of feed coming from 3-4 different sources (e.g. gas oils, kerosenes, ethane, etc.). In a complex olefins plant, the same

300,000 pounds of feed would be converted into 300,000 pounds of products divided among 10-12 different product draws ranging from heavy gas oil to hydrogen. The amount of CO₂ produced in the cracking process will be approximately 50 pounds. Compare this with the CO₂ produced from fuel combustion. The amount of fuel gas burned to produce the same 100,000 pounds of ethylene would be approximately 0.9-1.0 billion BTUs, or about 50 tons of CO₂ from combustion. It seems impractical to do a detailed material balance on 12-16 streams comprising some 300,000 pounds of feed and 300,000 pounds of products and expect to find 50 lb of CO₂ by difference. This is a huge amount of effort to account for less than 0.05% of the CO₂ produced in the process. Further, for ethylene process units co-located with a petroleum refinery or other chemical plant units, any off-gas is sent to the fuel gas system where it is mixed with other process gases from non-ethylene units in a fuel gas blend drum and then distributed to combustion units throughout the refinery and/or chemical plant.

As an alternative to the CEMS or mass balance option, subpart C would provide the appropriate methodologies for estimating GHG emissions from ethylene plants since, as EPA notes in its Technical Support Document for the Petrochemical Product Sector, "All of the GHG emissions associated with the ethylene process are from combustion units." The most accurate means of determining ethylene unit GHG emissions is to base the determination on fuel combustion, which is the methodology used currently by most ethylene units.

CEMS Requirements

EPA proposes the following in §98.243(a)(1)(ii) : "If you elect to install CEMS to comply with this subpart, you must route all process vent emissions to one or more stacks and use a CEMS on each stack (except flare stacks) to measure CO₂ emissions."

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

Flare Provisions

Section 98.243(a)(1) references §§98.253(b)(1)(i – iii) and (b)(2) for determining emissions from flares. EPA's proposed §§98.253(b)(1)(ii and iii) should also acknowledge that some facilities have an on-line GC capable of measuring the composition of the flared gas. Information from an on-line GC should also be allowed to be used in the carbon content and higher heating value

determinations for routine vents and also as an option for determining these values during times of start-up, shutdown, and malfunction vent scenarios.

Mass Balance Calculations

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

Sampling of Feedstocks

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

Equations Eq. X-1 through X-4

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

Equation X-1

Molar Volume Conversion Factor for Gas Streams – EPA states that this is 849.5 scf per kg-mole at standard conditions. EPA's proposed definition of Standard Conditions in §98.6 states that standard temperature is 60° F. Using the ideal gas law, this would yield the following for molar volume: $(10.73)(520)/(14.696) = 379.7$ scf per lb-mole $\times 2.2 = 835.3$ scf per kg-mole. It appears that EPA may have used 68° F as standard temperature in the calculation of molar volume. Therefore, EPA should decide on the correct standard temperature to use and align the definition of Standard Conditions with the calculation of molar volume for gases. This is an issue in other subparts of the proposed rule as well.

Material Balance Equations

EPA states on page 16537 of the preamble that organic liquid wastes that are collected for shipment offsite would also be considered an output in the carbon balance. This concept is not clear in the equations contained in the proposed rule and should be clarified. In addition, we believe that the owner/operator should have the option to improve the overall mass balance by

subtracting organic materials that are discharged from the process to a waste water sewer or collection system, accounting for materials vented to emission control devices, and to account for air emissions of organic materials. Therefore, the mass balance equation could look like this:

C_x = Carbon content of feedstocks in – Carbon content of all products out – Carbon content of liquid wastes - Carbon content of organics discharged to sewer – Carbon content of organics vented to an emission control device – Carbon content of organics emitted to atmosphere.

Note: The last three variables (discharges to sewer, vents to control devices, and vents to atmosphere) should be optional for those companies desiring to provide a higher quality carbon balance for their respective operations. Companies should also be allowed to use process knowledge and engineering calculations to determine these last four variables.

As stated in our comments above, a monthly accounting/material balance would allow for sufficient determination of all of the variables.

Monitoring and QA/OC Requirements - §98.244

Calibration Requirements

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

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

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

Gas Chromatographs

Some of the petrochemical processes may use an on-line GC to determine feed stream composition. EPA should recognize this technology and allow for calibration of the on-line GC using manufacturer's recommendations or perhaps EPA Performance Specification No. 9 in §98.244(b)(3).

Carbon Content Requirement

If the owner/operator is allowed to consider the carbon content of liquid waste streams, wastewater discharges, vents to control devices, and emissions to atmosphere, then the owner/operator should be allowed to use process knowledge and engineering calculations in order to determine the carbon content of these streams.

Procedures for Missing Data - §98.245

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

Data Reporting Requirements - §98.246

The proposed reporting requirements are excessive. The reporting requirements should be consistent with emissions inventory reporting requirements, and other supporting information should be part of record keeping. Other environmental reporting regulations do not require virtually all records to be included in submitted reports.

In particular, the excessive portions of the reporting rule for petrochemical production processes are §§98.246(a)(7) and (a)(8). Submittal of elements such as each carbon content measurement and information on the calibration of each flow meter will not improve the overall quality of the GHG emission calculation. EPA should keep in mind that the owner/operator will be certifying that the information provided is true, accurate, and complete to the best of his/her knowledge, which is a certification that ACC members take very seriously. The bulk of the information requested in proposed §§98.246(a)(7) and (a)(8) should be relocated to the recordkeeping requirements in §98.247.

K. Petroleum Refineries – Subpart Y

Definition of source category - §98.250

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: (new language underlined)

§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.

Calculating GHG emissions - §98.253

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.

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.

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). For a 500,000 barrel of crude per year 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.)

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.

L. Titanium Dioxide Production – Subpart EE

ACC supports the Agency's selection of reporting threshold for titanium dioxide (TiO₂) production facilities (*i.e.*, all chloride process facilities report). Since all facilities are estimated to exceed emissions of 25,000 metric tons CO₂e by a substantial margin, this would maintain more consistency in requirements throughout the rule.

Procedures for estimating data - §98.313

ACC supports the use of alternative emission estimates where continuous monitoring is not in use (§98.313(b)):

“Under this proposed rule, if you do not have CEMS that meet the conditions outlined in proposed 40 CFR part98, subpart C, we propose that facilities use the second option discussed above to estimate process-related CO₂ emissions. Refer to proposed 40 CFR Part 98, subpart C specifically for procedures to estimate combustion-related CO₂, CH₄ and N₂O emissions.

“Under this approach the total amount of calcined petroleum coke consumed would be assumed to be directly converted into CO₂ emissions. The amount of calcined petroleum coke can be obtained from facility records, as that data would be readily available.”
(preamble page 16552, section EE.3)

However, we disagree with the proposed regulatory language and the supporting statements in the preamble on page 16552, section EE.4:

“It is assumed that a facility would be able to supply data on annual calcined petroleum coke consumption data. Therefore, 100 percent data availability is required for all parameters.”

This is an incorrect assumption. There can be numerous reasons why data may not be available, may not be timely, or in the format EPA requires; *e.g.*, incorrectly calculated vendor reports that

are undetected, late submittals by vendors, computer malfunctions or failures, etc.) In cases where a required record is found to be missing or determined to be incorrect, we recommend that EPA provide a procedure for estimating missing data in §98.315 – Procedures for estimating missing data. We note that in many other rules, and even in this proposed rule, EPA recognizes that documents can be misplaced and data can be lost or incorrect (*i.e.*, not meeting quality assurance criteria). In this proposed rule, EPA provides in Subpart C procedures for missing data:

“§98.35 Procedures for estimating missing data.

“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.

“(2) For missing records of stack gas flow rate, *fuel usage* (emphasis added), and sorbent usage, the substitute data value shall be the best available estimate of the flow rate, fuel usage, or sorbent consumption, based on all available process data (*e.g.*, steam production, electrical load, and operating hours). The owner or operator shall document and keep records of the procedures used for all such estimates.

It is inconsistent for EPA to recognize the potential for missing data in one instance and deny a procedure for missing data in a subsequent paragraph of the same rule.

A more realistic approach to §98.315 would be to revise the rule language as follows:

“§98.315 Procedures for estimating missing data.

“Whenever data of petroleum coke consumption is unavailable, a substitute value for the missing consumption shall be used. The best available estimate of petroleum coke consumption shall be determined using all available information (*e.g.*, process data, coke consumption per mass of production, previous consumptions versus production rates, *etc.*). The owner or operator shall document and keep records of the procedures used for all such estimates.

Data Reporting Requirements - §98.316

ACC also disagrees with the proposal to require the documentation records and data identified in §98.316 and referenced on pages 16552, section EE.5 of the preamble:

“In addition we propose that facilities report the following additional data used as the basis of the calculations to assist in verification of estimates, checks for reasonableness, and other data quality considerations. The data includes: annual production of titanium dioxide, annual amount of calcined petroleum coke consumed, and number of operating hours in the calendar year.”

We disagree that there is a need within the purposes of this rule for any of the information identified in §98.316 to be reported specifically by production line.

All of the aforementioned information is CBI that could be used by competitors (U.S. and foreign) and is unnecessary to carry out the purposes of this proposed regulation. This data should only be available on site or as requested for security cleared EPA personnel and their security cleared contractors where a need is demonstrated for the purposes of this inventory.

Records that must be retained - §98.317

Although §§98.3(g) and 98.317 do not specifically require that records be maintained on-site, the preamble does indicate such intent:

“A full list of records that must be retained onsite is included in proposed 40 CFR part 98, subparts A and EE.” (preamble page 16553, section EE.6)

Many companies use central purchasing systems including off-site data and filing systems for material purchases including coke. These purchase order copies, etc., are not available from the site as the central groups only provide the summary data in plant cost sheets. We recommend that EPA revise the proposed language to ensure that any request for these records allow for a reasonable time frame within which to produce them.

M. Landfills – Subpart HH

Definition of Source Category - §98.340

As stated in §98.340(a), the source category consists of MSW landfills and industrial landfills including but not limited to landfills located at food processing, pulp and paper, and ethanol production facilities. EPA states in the preamble in Section V.HH.1 (74 FR 16557) that the majority of methane emissions from onsite industrial landfills occur at pulp and paper facilities and food processing facilities and provides data on the emissions from these sources. EPA does not provide emissions data for other industry sectors' onsite landfills to demonstrate the emissions are significant enough to warrant reporting. Also, Table HH-1 on page 16703 only provides default values to be used for calculating landfill emissions for food processing facilities and pulp and paper facilities, confirming for industrial sources only emissions from pulp and paper facilities landfills and food processing facilities landfills are significant enough to warrant reporting. Therefore, the source category should be revised to include only MSW landfills and industrial landfills at pulp and paper facilities and food processing facilities and reference to ethanol production facilities should be deleted from the parenthetical phrase at the end of §98.340(a).

Calculating GHG emissions - §98.343

The requirement in §98.343(a)(1) to start calculations 50 years prior to the year being reported must be flexible. Records of waste deposited in industrial landfills may not exist prior to when these landfills became regulated.

The factors in Table HH-1 listed under the heading “Waste model – bulk waste option” are not sufficiently diverse to support the wide range of materials that have been placed into industrial landfills. For example, a landfill containing waste polymer plastic would not be represented by a DOC of 0.2028, since polymer plastic cannot be biologically degraded. This further supports our position that EPA should limit industrial landfills subject to reporting to those at pulp and paper, and food processing facilities.

In §98.343, the expectation to start calculations 50 years prior to the year being calculated is established. Since the first year to be calculated is 2010, the data in Table HH-2 need only go back to 1960. Data in Table HH-2 from 1940 to 1959 should be deleted.

N. Wastewater Treatment – Subpart II

Definition of Source Category -§98.350

In §98.350, EPA defines a wastewater treatment system as “the collection of all processes that treat or remove pollutants and contaminants...and chemicals from waters released from industrial processes,” and further states that the Subpart II source category applies to “on-site wastewater treatment systems at pulp and paper mills, food processing plants, ethanol production plants, petrochemical facilities, and petroleum refining facilities.” A few aspects of the definition and its interrelationship with §98.2 are confusing as written and need further clarification as follows:

EPA has given conflicting information on which treatment systems are subject to reporting under this subpart:

- §98.350(a): EPA broadly defined the source category, suggesting that all emissions from all wastewater treatment systems that fall under the applicability thresholds of §98.2 and that are located at certain sources (pulp and paper mills, food processing plants, ethanol production plants, petrochemical facilities, and petroleum refining facilities) are covered under this Subpart.
- §98.353(a): EPA includes emission factors for use in Equation II-1 that are applicable to anaerobic treatment, aerobic treatment, and oil/water separators in Table II-1.
- §98.354: EPA provides QA/QC requirements only for anaerobic treatment systems.

To resolve this confusion, we recommend that EPA further clarify in §98.350(a) that the source category only includes anaerobic systems and that aerobic wastewater systems are exempted.

We also recommend that EPA clarify that the source categories to which this applies are defined elsewhere in Part 98.

Our proposed language is below (new language is underlined).

§98.350(a)

A wastewater treatment system is the collection of all processes that treat or remove pollutants and contaminants, such as soluble organic matter, suspended solids, pathogenic organisms, and chemicals from waters released from industrial processes. This source category applies to on-site wastewater treatment systems that include anaerobic treatment and that are located at pulp and paper mills, food processing plants, ethanol production plants, petrochemical facilities, and petroleum refining facilities as defined elsewhere in this Part.

The applicability portion of §98.350 covers only wastewater treatment systems at certain types of facilities (i.e. pulp and paper mills, food processing plants, ethanol production plants, petrochemical facilities, and petroleum refining facilities). This statement is considerably more limiting than the applicability statements of §98.2(a), which suggests that any facility covered under a subpart of the rule and otherwise meeting the thresholds of §98.2 would need to report wastewater emissions under §98.350. EPA should clarify §98.2 to indicate that reporting under the source category is only required if the facility meets any additional thresholds or applicability statements of that Subpart. Our proposed language is below (new language underlined).

§98.2(a)

The GHG emission reporting requirements, and related monitoring, recordkeeping, and verification requirements, of this part apply to the owners and operators of any facility that meets the requirements of either paragraph (a)(1), (a)(2), or (a)(3) of this section and the criteria for each category as defined elsewhere in this Part; and any supplier that meets the requirements of paragraph (a)(4) of this section:

GHGs to Report - §98.352

EPA has proposed the following for flare emissions:

For flares, calculate the CO₂ emissions only from pilot gas and other auxiliary fuels combusted in the flare, as specified in Subpart C of this part. Do not include CO₂ emissions resulting from the combustion of anaerobic digester gas.

However, Subpart C does not identify how to calculate emissions from flares and does not include flares in the list of equipment that is considered “stationary fuel combustion sources” (§98.30(a)), a position with which ACC fully agrees. Even if EPA meant for Subpart C to cover the emissions from flare pilot gas, the criteria for selecting the “tier calculation methodology” in §98.33(b) is inappropriate. The criteria are in part dependent on maximum rated heat input capacity of the combustion device. In the case of flares, nearly all of the heat input capacity is

dedicated to combustion of anaerobic digester gas which is not to be reported as an anthropogenic emission under §98.352(c). It would be inconsistent and inappropriate to determine applicability based on the capacity to produce non-anthropogenic emissions. In addition, the fuel use in and emissions from the pilot flame are small and should be excluded from detailed calculations because they are considered *de minimis* emissions as we discuss elsewhere in these comments.

For these reasons, and those discussed above in comments directed at Subpart C and §§98.6 and 98.30, EPA should remove the requirement to report CO₂ emissions from flares at wastewater treatment plants that are subject to reporting under Subpart II.

Calculating GHG Emissions - §98.353

Anaerobic Treatment Systems (except Digesters)

The Technical Support Document¹⁰ states that denitrification results from the anaerobic treatment of wastewater. However, anaerobic treatment typically results in little denitrification. For denitrification, anoxic treatment is typically used. *Anoxic* conditions are defined as an environment in which dissolved oxygen is not present in the water and nitrate (NO₃⁻) is used by the microorganisms as the electron acceptor.¹¹ Under these conditions, the nitrate is converted to nitrogen (N₂) and released to the atmosphere as a gas. The microorganisms use the oxygen as they degrade carbon sources and release CO₂ to the atmosphere. In contrast, *anaerobic* conditions are defined as environments in which dissolved oxygen is not present in the water and sulfur compounds (such as sulfate SO₄⁻²) are used as the electron acceptors. Under anaerobic conditions, sulfur (S), hydrogen sulfide (H₂S), and other sulfur-containing compounds such as mercaptans are formed.

This distinction is important because methane production is characteristic of *anaerobic* treatment, not *anoxic* treatment. EPA has proposed to require that all anaerobic treatment systems must calculate methane production via Equation II-1. Given the confusion between *anoxic* and *anaerobic*, EPA should clarify that only anaerobic conditions are the target of Equation II-1. If some systems use Equation II-1 to calculate methane emissions from anoxic treatment, it will vastly overstate the GHG emissions. The clarifications should be made with the following changes:

§98.6

Aerobic treatment means the treatment of wastewater with supplemental oxygen feed by the microbial reduction of complex organic compounds to CO₂.

¹⁰ *Technical Support Document for Wastewater Treatment: Proposed Rule for Mandatory Reporting of Greenhouse Gases*. USEPA Office of Atmospheric Programs – Climate Change Division. February 4, 2009. Section I.

¹¹ *Wastewater Technology Fact Sheet: Sequencing Batch Reactors*. US EPA. EPA 832-F-99-073. Sept 1999. p. 4.

Anaerobic treatment means the treatment of wastewater without supplemental oxygen feed by the microbial reduction of complex organic compounds to CO₂ and CH₄. Anaerobic treatment specifically excludes Anoxic treatment.

Anoxic treatment means the treatment of wastewater without supplemental oxygen feed by the microbial reduction of complex organic compounds to CO₂.

Definition of Oil/Water Separators

Another issue of concern for Subpart II is the definition of oil/water separator in §98.6 for which emissions must be calculated in §98.353(b). EPA defines the oil/water separator very broadly as “equipment used to routinely handle oily-water streams, including gravity separators or ponds and air flotation systems”. To define the oil/water separator as any equipment used to routinely handle oily-water streams would suggest that fugitive emissions from the dozens or more pieces of equipment separating oil and water upstream of the API separator would need to be included. This language could also be interpreted to cover stormwater ponds because they may contain a small concentration of hydrocarbons, though clearly far less than process ponds. We believe that EPA needs to narrow the definition of oil/water separator to limit it to the API separator and downstream equipment. We suggest using the definition in 40 CFR 63 Subpart G, Section 63.111:

Oil-water separator or organic-water separator means a waste management unit, generally a tank used to separate oil or organics from water. An oil-water or organic-water separator consists of not only the separation unit but also the forebay and other separator basins, skimmers, weirs, grit chambers, sludge hoppers, and bar screens that are located directly after the individual drain system and prior to additional treatment units such as an air flotation unit, clarifier, or biological treatment unit. Examples of an oil-water or organic-water separator include, but are not limited to, an American Petroleum Institute separator, parallel-plate interceptor, and corrugated-plate interceptor with the associated ancillary equipment.

If EPA chooses not to adopt its definition from 40 CFR §63.111, EPA should at least modify the definition to specifically exclude stormwater ponds from 40 CFR §98.6:

Oil/water separator means equipment used to routinely handle oily-water streams, including gravity separators or ponds and air flotation systems. This definition specifically excludes stormwater ponds and other devices that are not intended to handle process wastewater.

Oil/Water Separators

EPA has singled-out oil/water separators for GHG reporting without providing justification as to why these units demand special attention. Based on our information, the GHG emissions from a typical oil/water separator at a refinery are insignificant and should not be identified separately; again highlighting the need for a *de minimis* reporting threshold provision in the rule. As we discuss elsewhere in these comments, the *de minimis* provision would allow for a one-time

calculation of *de minimis* sources and then reporting the same number each year unless there are significant changes.

For a typical 150,000 BPD refinery, the wastewater flow will be approximately 5 MGD. Based on Equation II-2 (with which we have other concerns as discussed below), the CO₂ emissions would be only 50 metric ton/year from a covered separator.¹² Emissions from an uncovered separator (which are very rare in the industry today) would be 1,687 MTPY.¹³ These represent less than 0.003% and less than 0.1% of the typical refinery's emissions of 2,000,000 MTPY. The emissions from oil/water separators are very small compared to the total GHG inventory and therefore do not need to be reported for the purpose of an inventory of emissions. At a minimum, EPA should exempt from reporting any API separator that is covered and vented to a control device (the majority of separators) due to the small emissions.

In §98.353, EPA proposes to require that the volume of wastewater to an oil/water separator be measured and used as an input to Equation II-2. However, very few, if any, oil/water separators will have flow monitoring and this approach does not recognize the technical and practical difficulties of measuring flowrate for a two-phase (oil and water), or sometimes three-phase (oil, water, and oil/water emulsion), stream with inconsistent/varying specific gravities. Nor can these emissions be calculated with a simple material balance. Given the wide variation in sources, flows, and compositions to the oil/water separator in a facility, a material balance engineering calculation would be inaccurate and unsuitable to the purpose.

In addition, EPA has inappropriately applied Equation II-2 to calculate CO₂ emissions:

$$\text{CO}_2 = \sum [\text{EF}_{\text{sep}} * \text{V}_{\text{H}_2\text{O}} * \text{C} * 44/12 * 0.001] \quad \text{Equation II-2}$$

Where:

EF_{sep} = Emission factor for type of separator (kg NMVOC/m³ wastewater treated)

V_{H₂O} = Volume of wastewater treated (m³)

C = Carbon fraction in NMVOC (default = 0.6)

44/12 = Conversion from C to CO₂

0.001 = Conversion from kg to metric ton

EPA does not reference the source of the equation in the TSD.¹⁴ However, in the preamble,¹⁵ EPA says that the equation was “based on” California’s AB32 mandatory reporting rule.¹⁶ In turn, California’s rule relied on a document from CONCAWE.¹⁷

¹² CO₂ = [(0.111 Kg NMVOC/ m³)(18,927 m³/day)(0.6)(44/12)(0.001)(365)] = 50 MTPY

¹³ CO₂ = [(0.0033 Kg NMVOC/ m³)(18,927 m³/day)(0.6)(44/12)(0.001)(365)] = 1687 MTPY

¹⁴ *Technical Support Document for Wastewater Treatment: Proposed Rule for Mandatory Reporting of Greenhouse Gases*. USEPA Office of Atmospheric Programs – Climate Change Division. February 4, 2009.

¹⁵ 74 *Federal Register* 16560, April 10, 2009.

¹⁶ Title 17, California Code of Regulations §95113(c)(2)

In the CONCAWE report,¹⁸ the study and the resulting emission calculation were developed to estimate Non-Methane Volatile Organic Compounds (NMVOC):

$$\text{NMVOC} = \text{EF}_{\text{sep}} * \text{V}_{\text{H}_2\text{O}}$$

Where:

NMVOC = Emissions of NMVOC (kg)

EF_{sep} = Emission factor for type of separator (kg NMVOC/m³ wastewater treated)

V_{H₂O} = Volume of wastewater treated (m³)

The California Air Resources Board (CARB) used this equation, along with data from the IPCC, to generate an equation to calculate GHG emissions from oil/water separators. However, EPA's use of this equation is inappropriate for the following reasons:

1. NMVOC Destroyed in Control Device: CARB specifically cautions against double-reporting the CO₂ emissions¹⁹ from both the control device and the oil/water separator. However, EPA has done just that: CO₂ emissions from the combustion of NMVOC from oil/water separators are to be reported both under Subpart C (§§98.242(b), 98.352(c)) and Subpart II (§98.353(b)).
2. NMVOC Oxidized in Atmosphere (i.e. Not Destroyed in Control Device): The IPCC concluded²⁰ that non-CO₂ carbon emissions are eventually oxidized to CO₂ in the atmosphere. The IPCC directs that these GHG emissions should be included in national inventories. However, the *eventual* CO₂ emissions from NMVOC from other sources are not reported under part 98 and oil/water separator emissions should not be treated differently. EPA should use the data that is already reported to it under 40 CFR 51, Subpart A to estimate all NMVOC emissions and its eventual CO₂ conversion. In the case of oil/water separators, their inclusion in part 98 would again double-count the GHG emissions.

For these reasons, EPA should remove §98.353(b) from the rule.

¹⁷ CONCAWE = oil companies' European association for environment, health and safety in refining and distribution. www.concawe.org.

¹⁸ *Air pollutant emission estimation methods for E-PRTR reporting by refineries*. CONCAWE Air Quality Management Group's Special Task Force on Emission Reporting Methodologies (STF-69). Brussels, Belgium. Report no. 1/09, January 2009. Section 13.6.3.2.

¹⁹ *Attachments C to F. Supplemental Materials Document for Staff Report: Initial Statement of Reasons for Rulemaking. Mandatory Reporting of Greenhouse Gas Emissions*. California Air Resources Board. October 19, 2007. Attachment E.

²⁰ 2006 IPCC Guidelines for National Greenhouse Gas Inventories. Intergovernmental Panel on Climate Change. Volume 1, Chapter 7, Section 7.2.1.5.

Calculating Methane Destruction – Digester Gas Flow Monitoring

The techniques that EPA specified for flow monitoring (§§98.353(c), 98.354) do not reflect available technology and could increase the burden on facilities and result in lower data quality. EPA has proposed to require facilities to continuously measure gas flow under actual conditions (ACFM), temperature, and pressure. EPA is proposing that this information be averaged daily and then used to calculate gas flow under standard conditions (SCFM). This prevents facilities from using instrumentation that is widely available that will measure all three conditions (flow, temperature, pressure) simultaneously and report the flow in SCFM. An example of this is the Fox Thermal Instruments Model 10A Thermal Gas Flowmeter.²¹

Also in §§98.354(g) and (h), EPA is proposing that temperature and pressure monitors and flow measuring devices be calibrated and maintained as specified by the device manufacturer. Instead, we believe that EPA should require calibration according to good engineering and maintenance practices. This alternative wording will allow a facility to incorporate manufacturers' recommendations, equipment standards, and results of previous troubleshooting and maintenance.

EPA should allow, though not require, facilities to use instrumentation such as this by modifying the proposal as follows:

§98.353(c)

CH₄AD = Annual quantity of CH₄ generated by anaerobic digester, as calculated in Equation II-4 or Equation II-5 of this section (metric tons CH₄).

New material:

$$CH_4AD = \sum [V_{ns} * C_n / 100\% * 0.0423 * 1,440 \text{ minutes/day} * 0.454 / 1000]$$
 Equation II-5

Where:

$$CH_4AD = \frac{\text{Annual quantity of CH}_4 \text{ generated by anaerobic digester (metric tons CH}_4\text{/year)}}{\text{CH}_4\text{/year}}$$

$$V_{ns} = \frac{\text{Daily volumetric flowrate for day n, corrected to standard conditions (520}^\circ\text{R, 1 atm) as determined from daily monitoring specified in §98.354 (SCFM)}}{\text{SCFM}}$$

$$C_n = \frac{\text{Daily average CH}_4 \text{ concentration of digester gas for day n, as determined from daily monitoring specified in §98.354 (\%, wet basis)}}{\text{\%, wet basis}}$$

0.454/1000 = Conversion factor from pounds to metric tons

§98.354(g)

If required for Equation II-4, all temperature and pressure monitors must be calibrated using the procedures and frequencies specified by the device manufacturer established by good engineering and maintenance practices.

²¹ www.foxthermalinstruments.com

§98.356(n)

Temperature at which flow is measured (if required for Equation II-4 at facilities with anaerobic digesters).

§98.356(o)

Pressure at which flow is measured (if required for Equation II-4 at facilities with anaerobic digesters).

Monitoring and QA/QC Requirements §98.354

Digester Gas Methane Content Monitoring

In §98.354, EPA has requested comment on requiring monthly sampling of digester gas CH₄ content as an alternative to a continuous composition analyzer.²² We strongly support the proposed options to measure the methane content monthly or less frequently based on a statistical demonstration of the variability. There are a number of reasons why these options are preferable to continuous monitoring: (1) continuous methane monitoring is expensive; (2) continuous methane monitoring can be problematic, and (3) conditions in anaerobic digesters change at a slow pace relative to other treatment technologies.

EPA did not provide cost estimates for the continuous monitoring of methane. Typical costs of the uninstalled instrument can be as high as \$40,000²³ each, with installed costs of \$60,000²⁴ or more each. In contrast, periodic monitoring with instruments would cost about \$8,000.

There are also difficulties with monitoring digester gas due to its saturated humidity and impurities. Conditions such as these increase the maintenance on a system and shorten the life of that system, both of which increase costs.

As EPA has documented,²⁵ the hydraulic retention time in anaerobic digesters is measured in days, not hours as with other treatment systems. In addition, a facility that could expect variable influent conditions will have an equalization basin to reduce swings in concentration and make the digester feed more consistent. These design factors reduce the impact from influent changes and ensure more consistent, and hence effective, treatment. This also ensures that biogas production and characteristics (e.g., methane content) are relatively consistent and will vary over days rather than hours.

²² 74 *Federal Register* 16560, April 10, 2009.

²³ Anderson, Russell. *Preparing Your Landfill for an Offset Project*. SCS Engineers. December 11, 2008.

²⁴ *Continuous Methane Gas Analyzer Bid Summary*. Steuben County (NY) Purchasing Department. PW-08-062-B. 1/26/09.

²⁵ *Wastewater Technology Fact Sheet: Anaerobic Lagoons*. US EPA. EPA 832-F-02-009. Sept 2002.

For these reasons, EPA should allow for the monitoring of methane concentration in anaerobic digester gas to be either (i) monthly or (ii) less frequently based on a statistical analysis of the composition data.

Wastewater Samples

In §§98.354(a) and (c), EPA states that the location for the COD sample must represent the influent to the treatment process and requires reporters to collect a 24-hour flow-weighted composite sample at least once per week. Industrial facilities draw COD samples at the wastewater treatment plant discharge per NPDES permit conditions. Maintaining a compositor on the influent will be problematic due to oil, foam, sediment, phase separation, etc. Consistent with California's GHG emissions reporting program, reporters should be given the option to take daily grab samples of the influent to monitor for Total Organic Carbon (TOC) and use a conversion factor to convert TOC to COD.

EPA proposes to require that facilities collect all samples as flow-weighted composites but states that time-weighted composites would be acceptable if the COD content and flow "does not vary." Without further clarification, some may interpret "does not vary" as requiring 0% variation which is impossible for any system to achieve. EPA should clarify in the final rule that "does not vary" has a standard deviation that is less than 50% of the mean.

EPA also states that the location for the COD sample must represent the influent to the treatment process and that the location of the flow sample must correspond to the location of the COD sample. Industrial facilities do not have flow meters on the influent because (1) the NPDES-permit monitoring point is on the effluent outfall, (2) operation of meters in wastewater service is problematic due to oil, foam, phase separation, sediment, etc. and is much more difficult than monitoring the clean effluent, and (3) accuracy of flow meters in a gravity flow, possibly phase-separated system is a concern. As an option to inlet flow meters, reporters should be allowed to use outlet flow meters or engineering determination. This option is consistent with California's GHG emissions reporting program (Title 17 CCR Subchapter 10, Article 2).

We recommend these changes be reflected in §98.354(a) and (c) as follows: (new language underlined)

(a) The quantity of COD treated anaerobically must be determined using analytical methods for industrial wastewater pollutants and must be conducted in accordance with the methods specified in 40 CFR Part 136. If COD analysis is impractical due to the sample composition, the facility may measure Total Organic Carbon (TOC) and mathematically convert it to COD using a site-specific conversion factor based on actual analytical data. The quantity of TOC treated anaerobically must be determined using analytical methods for industrial wastewater pollutants and must be conducted in accordance with the methods specified in 40 CFR Part 136.

(c) For anaerobic treatment systems, facilities must monitor the ~~wastewater flow and~~ COD concentration and monitor or calculate the wastewater flow no less than once per week. The sample location must represent the influent to anaerobic treatment for the

time period that is monitored. The flow data sample must correspond to the location used to measure the COD. If flow monitoring at this location is impracticable, the facility must determine the flow using appropriate methods. Facilities must collect 24-hour flow-weighted composite samples, unless (1) they can demonstrate that the data for the COD concentration and wastewater flow into the anaerobic treatment system does not vary has a standard deviation that is less than 50 percent of the mean or (2) flow monitoring at that location is impracticable. In these cases ~~this case~~, facilities must collect 24-hour time-weighted composites to characterize changes in wastewater due to production fluctuations, or a grab sample if the influent flow is equalized resulting in little variability.

Procedures for Estimating Missing Data - §98.355

In §98.355(a), EPA describes the use of an averaging method for substitute data. We recommend that EPA also allow as an option the use of a method that is case-specific and justified by the operator based on facility operating knowledge or data. The averaging method may not be appropriate in all cases. For example, if the data gap should occur during a known spike or drop in concentrations or flow, it would not be appropriate to use the data that surrounds the gap. Only the operator will have the knowledge to make that assessment.

Data Reporting - §98.356

In §98.356(b), EPA has proposed to require that systems report the “percent of wastewater treated at each system component.” We find this statement ambiguous. Industrial wastewater treatment plants are complex systems that can contain multiple treatment steps that proceed both in parallel and series. Portions of the wastewater can be removed from or added to the system at different points. Multiple conclusions can be drawn from the request. For example, is EPA seeking the amount of wastewater that is treated:

- In an anaerobic digester vs. other anaerobic technology?
- In an anaerobic digester or other technology vs. aerobic technology?
- In a neutralization basin?
- In an equalization basin?
- In an oil/water separator?

In addition, this information is not required for the GHG emissions from the facility. As discussed elsewhere in these comments, EPA has proposed to request an unprecedented amount of detailed data throughout the rule, much of which is not important to GHG emission calculations.

We suggest that EPA remove §98.356(b) in its entirety from the final rule.

EPA has proposed in §§98.356(m), (n), and (o) to require that the data from continuous methane, temperature and pressure monitors be submitted. As written, this is an overwhelming amount of data. Continuous monitors will collect a data point many times per minute. This means that EPA will require facilities to submit millions of data points every year. EPA has never before required such information to be submitted for emissions inventory reports and should not begin now unless it can present compelling reasons to do so. As discussed throughout our comments, EPA has proposed to require an unprecedented amount of detailed data be gathered and submitted. Detailed data such as methane content, temperature, and pressure should be maintained by the facility and made available for inspection in keeping with existing practice.

We suggest that EPA remove §§98.356(m), (n), and (o).

EPA has proposed in §98.356(r) to require that facilities with anaerobic digesters report “fugitive methane.” This is also ambiguous. As EPA notes,²⁶ it uses multiple definitions for “fugitive.” For example, in some sections, “fugitive” includes flare emissions but in other sections it does not. EPA provides no clarification which definition should apply for wastewater plants in the Preamble, Technical Support Document, or proposed rule language.

For Subpart II, EPA should define “fugitive methane” emissions to be that methane which is fed to the destruction device (e.g. flare, engine) but not destroyed.

Table II-1 – The default values for uncovered DAF and IAF units and covered DAF and IAF units are 4.00E-34 kg NMVOC/m³ wastewater and 1.2E-44 kg NMVOC/m³ wastewater, respectively. These default factors will result in very low emissions that are insignificant in comparison to total refinery GHG emissions. Thus, emissions from DAFs and IAFs should not be included in the report.

O. Suppliers of Petroleum Products – Subpart MM

Definition of the source category - §98.390

The scope of this subpart is unclear. While the category is clearly intended to capture fuel production from petroleum refineries, the definitions of “petroleum products” and “petrochemical feedstocks” are sufficiently general to cause confusion as to whether chemical manufacturing operations that are not refineries are part of the source category, or if EPA intended for refineries to report production of materials that are not intended to be combusted by the refinery customer base.

²⁶ 74 Federal Register 16529, April 10, 2009.

One example is the U.S. polymers and resin manufacturing industry. This industry sector is comprised of large companies with manufacturing locations around the globe. They consume liquid organic chemical feedstocks and produce solid plastic polymers and liquid organic chemical by products. They may import some portion of the liquid chemical feedstocks they consume and may export some of the liquid organic chemical by products they produce. None of these materials are intentionally combusted as fuel.

Based on the construction of Table MM-1 of Subpart MM, it appears that petrochemical feedstocks are considered a subgroup of petroleum products. The definition of “petrochemical feedstocks” in §98.6 states that they are “feedstocks derived from petroleum for the manufacture of chemicals, synthetic rubber, and a variety of plastics” (emphasis added). Clearly, many of the liquid organic chemical feedstocks for polymer and resin manufacturing are “feedstocks derived from petroleum for the manufacture of...plastics” and could be classified as “Miscellaneous Products” under the heading of Petrochemical Feedstocks in Table MM-1.²⁷ This appears to mean that most polymer and resin manufacturing companies are importers and exporters of petroleum products and thus squarely within the source category described in the introductory sentence of §98.390 and paragraphs (c) and (d) therein. We do not believe that EPA intended this outcome, because none of the liquid organic chemical feedstocks used in the polymers and resins manufacturing industry are imported expressly to be combusted and few of the liquid organic chemical byproducts are exported for fuel use.

In the Preamble to the rule, the EPA is directed to develop a rule for reporting of emissions, including those resulting from upstream production and downstream sources, as follows:

“...require mandatory reporting of GHG emissions above appropriate thresholds in all sectors of the economy of the United States.”

The preamble states that EPA should “use its existing authority under the Clean Air Act” to develop a mandatory GHG reporting rule. “The Agency is further directed to include in its rule reporting of emissions resulting from upstream production and downstream sources, to the extent that the Administrator deems it appropriate.” EPA has apparently interpreted that language to confirm that it may be appropriate for the Agency to exercise its CAA authority to require reporting of the quantity of fuel or chemical that is produced or imported from upstream sources such as fuel suppliers, as well as reporting of emissions from facilities (downstream sources) that directly emit GHGs from their processes or from fuel combustion.

This language describing EPA’s authority is directed toward reporting of emissions, not quantities of materials imported or exported. Many uses of petroleum products will not result in emissions, especially not in the short term. Using the plastics example above, production involves incorporating petroleum-based chemicals into engineered thermoplastics. The carbon in the plastics would not be released as emissions unless the plastic is incinerated, in which case the emissions may require reporting under a separate section of this rule. Engineered thermoplastics are designed for long use life and have properties preventing ready biodegradation and therefore the carbon is not emitted but is actually sequestered in the resin product. Therefore, the

²⁷ Methanol, another common liquid chemical feedstock in polymers and resin manufacturing, is also listed in Table MM-1.

calculated emissions resulting from the import/export of chemicals will result in erroneous calculation of potential emissions and appears to exceed the boundaries of statutory authority for this rule. We suggest that the requirement for reporting import/export be limited to only refineries and the fuels listed in Table MM-1 after the deletion of "miscellaneous products."

Data reporting requirements - §98.396

EPA is requesting reporting data on the petroleum products produced on a facility basis and reporting at a corporate level the petroleum products they import or export. In the preamble (74 FR 16570), EPA indicates that the rationale for this separate reporting is that it is proposing coverage at the facility level where feasible (e.g., refineries) and proposing corporate reporting only where facility-level coverage may not be feasible (e.g., importers and exporters). EPA makes no claims as to the quality or accuracy of the information provided when done on a facility or corporate basis.

Industry believes that using the "elaborated mass balance approach" would not result in more accurate data when calculations are performed on a facility basis versus a corporate basis. The calculations would be simplified if the necessary data is gathered at a corporate level before performing the GHG emission calculations. This will follow a process similar to the one used by EIA to gather the nationwide fuel information. In addition this will reduce that amount of CBI information submitted to EPA. Since the required information has to be gathered for EIA, the amount of additional data reporting and recordkeeping required by the GHG reporting rule would be significantly reduced.

Blending of gasoline with bio-mass fuel (ethanol) is done at a terminal. Terminals may be located at the refinery and/or at remote locations, and may be owned by a third party who purchase fuels from many sources. Therefore, some of the petroleum products (Product_i in equation MM-1) leaving the refinery may not contain biomass. To estimate CO₂ emissions from biomass, we suggest using the amount of biomass fuel used at a corporate level and the default factor. The number of CO₂ generated from biomass would then be subtracted from the total fuel sales recorded at the corporate level.

P. Suppliers of Natural Gas and Natural Gas Liquids – Subpart NN

GHGs to report - §98.402

Reporting CO₂ from suppliers of natural gas and natural gas liquids under Subpart MM will significantly over report emissions of CO₂. According to §98.402(a), "Natural gas processing plants must report the CO₂ emissions that would result from the complete combustion or oxidation of the annual quantity of propane, butane, ethane, isobutene and bulk NGL's sold or delivered for use off site."

One example of the over-reporting issue is the case of NGLs (raw and fractionated) imported into a feedstock purification unit in an olefins plant. The purification unit processes the NGLs. Some compounds are sent to the olefins plant as feedstock and some are sold to third parties as either fuel or feedstock depending on the economics. Normally, feedstock is the economically preferred option. If the third party sales go into the fuel market, the buyer is usually a large fuel supplier or user.

Multiple counting of CO₂ occurs as indicated below.

- The CO₂ from the imported NGL's would be reported by the supplier. None of this NGL is directly combusted.
- The CO₂ from processed NGLs sold as feedstock would also be reported. None of this NGL is directly combusted.
- The CO₂ from the processed NGLs sold as fuel would likely be reported again if sold to another supplier or again under the Subpart C, Combustion, if sold to a user.
- The NGLs sold to the supplier have the potential to be reported again by the ultimate user if the user emits more than 25,000 tons.

CO₂ emissions from olefins are primarily from combustion - over 99%. Some of the fuel is imported (reported by suppliers) but the majority of the fuel is internally produced in the cracking process. The combustion emissions are double counted since they are first counted by the NGL supplier. A very minimal amount (less than 1%) of CO₂ emissions are from flaring and decoking. EPA should recognize the issue of double counting these CO₂ emissions, and allow facilities to account for these emissions subject to one of the applicable subparts.

Q. Suppliers of Industrial Greenhouse Gases – Subpart OO

EPA appropriately segregated the fluorochemical production facility reporting requirements in subpart L from the fluorinated GHG marketing reporting requirements in subpart OO. Subpart L is limited to facilities that produce a fluorinated GHG, whereas subpart OO is limited to facilities marketing fluorinated GHGs for sale into commerce. Because of the millions of potential downstream fluorinated GHG users, including automobiles, residences, commercial buildings, and medical propellants, individuals, companies, and other entities actually responsible for industrial GHG emissions should not be required to report their emissions. EPA appropriately identified the introduction to commerce as the downstream industrial gas reporting threshold. However, many facilities removing and destroying industrial GHGs will also be required to report under proposed Part 98 subparts L and/or O. Those facilities should have the option of reporting industrial GHG destruction under any applicable part 98 subpart.

Fluorinated GHG suppliers include domestic and foreign bulk manufacturers of gases, plus importers of gases, either in bulk or gases contained in products such as portable air conditioners, vehicles, and GHG-blown foam products. EPA should require reporting of all fluorinated GHGs

entering the United States, and not exclude industrial GHGs contained in products from reporting.

EPA should base subpart OO reporting on the existing EPA voluntary HFC reporting system, which includes periodic reporting of produced industrial GHG and on per-shipment bulk industrial GHG imports and exports. Each fluorinated GHG report should be consistent with the reporting requirements for production, imports and exports in EPA's current HFC electronic data pilot project. This HFC pilot reporting system has been designed by EPA and HFC producers to be consistent with the current ODS class I and class II recordkeeping and reporting requirements found in 40 CFR 82.13 and 82.24. HFC producers are familiar with these reporting requirements and have streamlined internal processes to be consistent with the data requirements of the current reporting requirements. This proposed rule contains a number of requirements that are inconsistent with the current HFC reporting and recordkeeping include such requirements as reporting in metric tonnes vs. kilograms, annual reporting vs. quarterly reporting, and additional recordkeeping for exporters. This proposed reporting also goes beyond the scope of the HFC reporting system to include the reporting of non-GHG reactants and by-products. In addition, any recordkeeping and reporting requirements should be applicable also to "products containing" an HFC which is consistent with the current language in the latest draft of the American Clean Energy and Security Act of 2009. EPA could and should adapt the import section of the voluntary HFC reporting system to collect data concerning industrial GHGs imported and contained in products.

Calculating GHG emissions - §98.413

With respect to fluorinated GHGs, destruction is defined in §98.6 as the "...expiration of a fluorinated GHG to the destruction efficiency actually achieved. Such destruction does not result in a commercially useful end product." Subpart OO requires estimation of the total mass of each fluorinated GHG destroyed on an annual basis. ACC requests clarification of this definition considering industry practices for air pollution control at GHG production facilities. Specifically, pollution controls devices (e.g., scrubbers) designed to control emissions of pollutants such as HF, HCl or F₂ in the process gas stream, which also contains low concentrations of fluorinated GHGs, should not be considered devices for "destruction" of the fluorinated GHGs. If fluorinated GHGs pass through these control devices relatively unchanged, ACC would consider this pass-through process to be an emission, rather than destruction.

Monitoring and QA/QC requirements - §98.414

The proposed rule includes the following monitoring and associated QA/QC requirements:

- mass of fluorinated GHGs or nitrous oxide coming out of the production process measured using flow meters, weigh scales or a combination of volumetric and density measurements at least daily with an accuracy and precision of 0.2% of full scale or better [§98.414(a)];
- mass of any used fluorinated GHGs or used nitrous oxide added back into the production process upstream of the output measurement in (a) measured at least daily using flow

meters, weigh scales, or a combination of volumetric and density measurements at least daily with an accuracy and precision of 0.2% of full scale or better [§98.414(b)];

- mass of fluorinated GHGs or nitrous oxide fed into transformation process measured at least daily using flow meters, weigh scales, or a combination of volumetric and density measurements at least daily with an accuracy and precision of 0.2% of full scale or better [§98.414(c)];
- mass of unreacted fluorinated GHGs or nitrous oxide permanently removed (recovered, destroyed or emitted) from the transformation process measured at least daily using flow meters, weigh scales, or a combination of volumetric and density measurements at least daily with an accuracy and precision of 0.2% of full scale or better [§98.414(d)];
- mass of fluorinated GHG or nitrous oxide sent to another facility for transformation measured at least daily using flow meters, weigh scales, or a combination of volumetric and density measurements at least daily with an accuracy and precision of 0.2% of full scale or better [§98.414(e)];
- mass of fluorinated GHG sent to another facility for destruction measured at least daily using flow meters, weigh scales, or a combination of volumetric and density measurements at least daily with an accuracy and precision of 0.2% of full scale or better [§98.414(f)]; and,
- mass of fluorinated GHGs fed into the destruction device measured at least daily using flow meters, weigh scales, or a combination of volumetric and density measurements at least daily with an accuracy and precision of 0.2% of full scale or better [§98.414(g)].

All measurement devices shall be calibrated prior to the first reporting year and at least annually thereafter, while gas chromatographs shall be calibrated at least monthly.

The proposed rule requires that scales, flow meters and other measuring instrumentation must have accuracy and precision of 0.2%, which essentially prescribes the use of Coriolis flow meters where such meters are appropriate. Products subject to subpart OO reporting are typically sold in bulk containers, portable containers, or contained in domestically produced or imported products. EPA proposed data quality objectives that are not related to how industrial GHG products are managed. Typically, these products are dispensed in weigh scale configurations, which are managed according to National Institute of Standards and Technology (NIST) Handbook 44. Handbook 44 manages weigh scale accuracy as a tolerance weight as a fraction of the total amount weighed, not as any accuracy or precision fraction. For instance, the typical fluorochemical product disposable 30 pound cylinder loading standard is calibrated to a tolerance of +/- 0.1 to 0.5 pounds. EPA should recognize the current NIST standard and not create conflicting weigh scale requirements that were developed over many years to properly manage product custody transfer. ACC recommends that that all twenty-three facilities subject to subpart OO may continue using existing measurement instrumentation and engineering-based process knowledge.

Mandated annual calibration of all flow meters, scales, load cells and volumetric and density measures used to measure production and related parameters is inconsistent with accepted engineering principles. Empirical data collected throughout routine operations, as well as

preventative and corrective maintenance, is used to determine equipment performance and reliability. This in turn is utilized over time to refine calibration and maintenance requirements and schedules. An arbitrary annual calibration requirement defeats the value of this knowledge, and it ultimately adds cost, promotes premature equipment failure, and increases emissions due to unnecessary shutdowns and start-ups. ACC recommends that an initial calibration or manufacturer calibration warranty be required for all new and replacement measurement equipment and on-going calibration be based upon a schedule determined by the facility considering operational data and manufacturer specifications.

EPA does not address the importation of industrial GHGs contained in products. EPA notes in the TSD that industrial GHGs contained in products represent approximately 10% of the total industrial GHG market, and should be included in any part 98 reporting system. Not requiring reporting of these imported industrial GHGs represents a disincentive for domestic manufacturers, who would have to carry the burden of reporting that would escape importers. Because very few companies import appliances and blown-foam stock into the United States, EPA would not be increasing the compliance burden by requiring all industrial GHGs be reported under subpart OO.

Section 98.414 does not address data quality associated with imported GHG. EPA should rely on import documents generated by the United States Customs Service as the appropriate reporting basis for imported bulk GHGs. Facilities receiving bulk industrial GHG shipments that were dispensed in compliance with Subpart OO (by use of appropriately calibrated packaging weigh scales, for instance) should be allowed to report either the amount of material introduced to the manufacturing process or by the receipts of the bulk shipping containers as was reported by the company reporting the shipment of the material. EPA should encourage consistent reporting between suppliers and users of industrial GHGs.

Procedures of estimating missing data - §98.415

The proposed rule states that substitute data for missing quality-assured parameters shall be either a secondary measurement for mass and flow measurements, or the arithmetic average of parameter values immediately preceding and following the missing data. If the methods described in §§98.414(a)(1) and 98.414(a)(2) are likely to under- or over-estimate the parameter value, a best estimate shall be developed with documentation on the methods used, and rationale and reasons to explain why (a)(1) and (a)(2) would under- or over-estimate the parameter.

Missing and/or suspected erroneous data is undesirable, but frequently unavoidable at complex manufacturing facilities. The methodology proposed for substitute data is unusually burdensome requirement that will not materially change overall emissions validity. Furthermore, efforts required by this prescribed methodology and associated documentation add labor cost which can be better applied to correcting the cause of the missing data. ACC proposes using the systems detailed in 40 CFR Part 63 or 64, with the 75% minimum data availability systems, already promulgated by EPA. In addition, much of the data to be reported in subpart OO relies on United States Customs Service importation and export records, which cannot be subject to any missing data systems. The importation of products containing industrial GHGs do not adapt to

traditional data management schemes, but rely on calculations of total industrial GHG content or appliance charge amounts. EPA should strike §98.415 from the proposed subpart OO.

Data reporting requirements - §98.416

The proposed rule requires reporting of total mass of each fluorinated GHG and nitrous oxide produced, total mass of each fluorinated GHG and nitrous oxide transformed, total mass of fluorinated GHG destroyed, total of any fluorinated GHG and nitrous oxide sent to another facility for transformation, total mass of any fluorinated GHG and nitrous oxide and nitrous oxide sent to another facility for destruction, total of each reactant fed into the production process, total mass of each non-GHG reactant and by-product permanently removed from the production process, and total mass of used product added back into the production process for reclamation. Additionally, full explanation for the reason and length of time quality-assured parametric data was missing, as was the information required by §98.415.

This abovementioned data must be collected to complete the necessary mass-balance calculations to develop the emissions estimate prescribed in subpart L (§98.123). EPA surely recognizes that this data is extremely sensitive and confidential business information, which could be utilized to deduce process costs, efficiencies and competitive strategies. In certain instances, this data can be proprietary or protected by patent. ACC recommends that rather than submitting this information as part of the annual report, this data shall be maintained at the respective facility and available for review at the facility, if necessary, as provided in §98.3(f). In lieu of this data submission, the final rule should recognize and allow self-verification and certification similar to the Clean Air Act Title V Operating Permit program where facilities represent their compliance with applicable regulations and permit requirements without submission of the detailed data supporting that certification.

In §§98.416(d) and (e), the proposed rule requires bulk importers and bulk exporters of fluorinated GHGs or nitrous oxide to submit an annual report summarizing their imports/exports at the corporate level, except for transshipments and heels. The report shall submit information including, but not limited to the following:

- total mass of each fluorinated GHG and nitrous oxide imported/exported in bulk;
- names and address of the importer/exporter and recipient of the shipment;
- quantity imported/exported by chemical; and,
- date of import/export.

This data should be reasonably available from currently required importing and exporting records; however, EPA surely recognizes that this data is CBI, which discloses customer base, market share and similar data that could be utilized to deduce cost/pricing structures, as well as competitive strategies. Furthermore, off-shore suppliers and customers may choose not to do business with U.S.-based companies if this information is made available in the public domain. ACC recommends that rather than submitting this information as part of the annual report, this

data shall be maintained at the respective facility and available for review at the facility, if necessary, as provided in §§98.3(f) and 98.417.

Records that must be retained - §98.417

The proposed rule requires persons who import a container with a heel shall keep records of the amount brought into the United States that document that the residual amount in each shipment is less than 10 percent of the volume of the container and will:

- (1) remain in the container and be included in a future shipment;
- (2) be recovered and transformed; or
- (3) be recovered and destroyed.

Customers routinely return containers with residual material for a variety of reasons. In rare instances, this material will be imported by a hazardous waste management facility directly for destruction. Normally, this material was originally produced by the importer, and the material will be managed as noted in (1) – (3) of §98.417(e), and the container will be returned to service since it has significant intrinsic value. In addition to (1), (2) and (3), the residual material may be recovered and resold, which we recommend EPA add to the final rule as a fourth practice. Expensive commodities such as fluorinated GHGs and nitrous oxide are routinely top-filled and included in a future shipment, i.e., practice (1), or they are removed, recovered and included in a future shipment, i.e., recommended practice (4). ACC recommends that practice (4) be added to the practices already contained in the proposed rule at §98.417(e), and that the definition of “heel” be revised in §98.417(e) to any volume of the original shipment in the original container. This will prevent double-counting the production of the original material after export, customer use and subsequent import.

Furthermore, §98.417(d) should include an option (4) to allow facilities to reprocess heel material recovered from a returned industrial GHG cylinder that may not be suitable for direct resale but would add value as a recovered and reprocessed product.

R. Suppliers of Carbon Dioxide – Subpart PP

Definition of the source category - §98.420

EPA should revise the subpart PP applicability at §98.420(a) to clarify that suppliers of CO₂ are those entities intending to isolate CO₂ to place the product into commerce. Member companies may separate CO₂ as part of a chemical manufacturing process that is not “manufactured” to supply downstream customers, which does not meet EPA’s intent of identifying the CO₂ placed onto the market and potentially emitted downstream of the manufacturing facility.

EPA should require CO₂ metering at the point where the material enters the stream of commerce, not where it is separated out of the manufacturing process. Liquified CO₂ is easier to measure than raw CO₂. Some member companies manufacture CO₂, transfer it to a company for processing, liquefaction, and marketing to downstream users. Manufacturers should be able to

use production data from the entity liquefying the CO₂, regardless if the liquefaction step is conducted by the reporter or by a downstream entity engaged in arms-length sale of the CO₂.